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Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975 - 2000 A.D.

By the MONTANA UNIVERSITY COAL DEMAND STUDY TEAM

Final Report

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MONTANA UNIVERSITY COAL DEMAND STUDY

FINAL REPORT

Parts I and II

Projections of Northern Great Plains
Coal Mining and Energy Conversion Development
1975 - 2000 A.D.

-by-

Dr. Thomas M. Power	University of Montana
Dr. John W. Duffield	University of Montana
John R. McBride	University of Montana
Dr. Richard L. Stroup	Montana State University
Terry D. Wheeling	University of Montana
William D. Tomlinson	University of Montana
Walter J. Thurman	Montana State University
Dr. Arnold J. Silverman	University of Montana

Research Support from NSF/RANN

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PREFACE

This study projects the probable levels of coal development in Montana and adjacent Northern Great Plains (NGP) states in the next five, ten, and twenty-five years. The final report is in four parts. Part I provides an outline of the methodology and a summary of the projection. Part II is a detailed comparison of our results with other projections of NGP coal development, principally the Northern Great Plains Resources Program's National and Regional Energy Considerations Work Group Report and the Federal Energy Administration's Project Independence Report. Part III is a compilation of the fourteen working papers on which the final projections are based. Part IV is a listing of computer programs developed for the project and the printout for the price-sensitive projection model.

This study is the first step in developing a detailed price-sensitive study of the demand for Northern Great Plains coal. We have not explored the interfuel substitution problem, alternative coal-based technologies that may become commercial on a modest to large scale in the next twenty-five years (MHD, coal liquefaction, in-situ gasification, fluidized bed combustion, and others) or the restraints that a range of environmental, land use, and taxation laws and regulations may place on coal resource and conversion development.

Given the assumptions and methodologies employed, this work will, we believe, project the levels of coal development in the Northern Great Plains required under a variety of electric growth rate assumptions to satisfy the demand for coal by thermal-electric generating

plants within the market areas we define. An analysis of the potential for coal gasification in the Northern Great Plains is also presented. Methodological analysis is presented in enough detail so the reader may provide alternative assumptions and thus generate other projections. We are also aware that governmental intervention may result in significant changes in projection levels and rates of growth, rendering our "least cost" analysis meaningless in the short term.

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PART III. WORKING PAPERS

- #1 "Electric Energy Demand and the Demand for Northern Great Plains' Coal," by Thomas M. Power.
- #2 "Forecasting Coal Gasification Activity," by Richard L. Stroup and Walter Thurman.
- #3 "The Geographic Market for NGP Coal," by Terry D. Wheeling.
- #4 "NGP Coal Contract Data," By William D. Tomlinson.
- #5 "Nuclear Energy Raw Material Supply," by Arnold J. Silverman.
- #6 "Projections of Hydroelectric Generation in the Northern Great Plains Coal Market Area," by John R. McBride.
- #7 "Projections of Nuclear Fueled Electric Generation in the Northern Great Plains Coal Market Area," by John R. McBride.
- #8 "Costs of Flue Gas Desulfurization for Electric Generating Plants," by John R. McBride.
- #9 "Advanced Coal Cleaning and Energy Conversion," by John R. McBride.
- #10 "Potential for Conversion of Oil to Coal-Fired Steam Electric Generators," by John R. McBride.
- #11 "The Status of Supplementary Control Systems," by John R. McBride.
- #12 "Econometric Projections of Electric Energy Demand in the Northern Great Plains Coal Market Area," by John W. Duffield and Terry D. Wheeling.

- #13 "Environmental Laws and Regulations of Northern Great Plains Coal Market Area Swing States," by William D. Tomlinson.
- #14 "NGP Coal Use in Response to Natural Gas Shortfalls," by Walter Thurman and Richard L. Stroup.

PART IV. COMPUTER PRINTOUT AND PROGRAMS

A. Montana University Coal Demand Study Electric Energy Demand Projections.

Volume I:

- Market Totals.
- State Totals.
- Data Files.

Volume II:

- State Projections.

B. Montana University Coal Demand Study Programs.

- Projec.F4
- Ustat.F10
- Alpha.F4
- Alphas.F4
- Hyper.F4

BIBLIOGRAPHY

SUMMARY

In this summary we provide an outline of our methodology and, in tabular form, a brief presentation of our results. This discussion is repeated in much greater detail in Part I following.

Methodology

Based on an extensive review of past regional and national studies,¹ the basic methodology adopted was as follows:

A. Market Definition

We defined the geographic market in which Northern Great Plains (NGP) coal is competitive. Our analysis shows that the market boundary was not significantly affected by reasonable alternative levels of transportation costs or coal production costs.² However, the market boundary was sensitive to federal air pollution control policy (due to the additional charge for pollution control equipment and operation³): regulations requiring only Supplementary Control Systems (SCS)--which may include tall stacks and/or Intermittent Control Systems (ICS)--resulted in a 13-state "All SCS" market; but if air pollution emission controls requiring flue gas desulfurization (FGD) or the combustion of low sulfur coal are enforced, an expanded 21-state "All FGD" market results. The All FGD market coincides with the set of states for which firm NGP coal contracts through 1980 exist.⁴

¹Thomas Power, Working Paper #1 (See Appendix I).

²Terry Wheeling, Working Paper #3.

³John McBride, Working Papers #8, #9, #10, and #11.

⁴William Tomlinson, Working Paper #4.

B. Electric Energy Demand

Next we projected the demand for electric energy in the market area open to Northern Great Plains coal. One approach was to use constant annual growth rates of 1%, 3%, and 5% to bracket the range of projections for the growth in electric energy demand resulting from both historical trend and price-sensitive econometric models.⁵ These growth rates were simply applied to existing generation in the area where NGP coal has a market advantage. Table A in Appendix I summarizes this projection. An additional projection is based on our own market-specific price-sensitive analysis.⁶ Here the permutations correspond to increasingly higher rates of real price increase for electricity and gas in the future. The annual rates of growth in real price used were 0% for both electricity and gas, then 1% and 3%, 3% and 5%, and 5% and 7% for electricity and gas prices, respectively. Table A in Appendix II summarizes this projection.

C. Fuel Mix

Only part of the projected consumption of electricity in the market area open to NGP coal will be produced by burning coal. It is therefore necessary to allocate the projected generation among competing fuels in order to estimate coal-fired generation. Based on the assumption that coal will maintain its current share of electric generation fuel (currently 39% in our All FGD market and 13.8% in our All SCS market), Table B in each of the Appendices provides a projection of coal-fired generation. An

⁵Thomas Power, Working Paper #1. The econometric model predicts sales and consumption. However, these growth rates were applied to the 1973 generation figures, reflecting the assumption that the ratio of sales/generation is approximately constant.

⁶John Duffield, Terry Wheeling, Working Paper #12.

alternative approach for determining the fuel mix is to project nuclear and hydro generating capacity,⁷ and allocate the remaining "residual" electric generation to coal (see Table F).

D. Coal Source

The final element in the projection was to estimate how much of the coal demand in the market open to NGP coal will be met by NGP coal as opposed to coal from other sources. Again, the implications of two alternative assumptions were examined: (1) that NGP will supply all the new demand for coal in the market area, or (2) that NGP will supply a share equal to its contract-based projected share for 1980.

The basis of both of these approaches and our specific projection for 1980 is our index of coal contracts for the Northern Great Plains.⁸ The contract data have been gathered from a wide variety of sources, including directories assembled by the Wyoming Geological Survey, the Montana Energy Advisory Council, news releases and articles, environmental impact statements and assessments, and certified statements entered into official administrative proceedings. These contract data represent the best information publicly available regarding contracts for NGP coal.

E. Gasification

The demand for NGP coal to be used for coal gasification and for direct combustion as a boiler fuel to replace natural gas was also estimated. The demand for NGP coal to be used as a feedstock for coal gasification was determined by first calculating what it would cost to convert coal into pipeline quality gas. The value of that gas was then determined

⁷Arnold J. Silverman, Working Paper #5; John McBride, Working Papers #6 and #7.

⁸William Tomlinson, Working Paper #4.

by comparing synthetic natural gas with various competing substitutes. The response of gaseous fuels to much higher fuel prices and the effects of various governmental policies were also studied. The results of these analyses, which indicate that coal gasification is unlikely without government intervention, are shown in Summary Table 3. Table 3 also gives an upper limit estimate of the potential consumption of NGP coal as a boiler fuel. This estimate was calculated by projecting a theoretical natural gas shortfall and allocating a share of that shortfall to coal.

F. Alternative Scenarios

As will be discussed at length below,⁹ the most reasonable permutation of assumptions appears to be the All FGD market, the assumption of a constant share of total generation being coal-fired, and a share of this coal demand assigned to the NGP on the basis of what the 1980 contracts indicate that share will be. In the following two summary tables, one for each of the electrical generation approaches, these permutations are shown. In addition, the related state-specific coal projections for the individual NGP states are given in Tables 4 and 5. Each state's allocation is based on its 1980 contract share.

We should emphasize that our analysis is meant not only to project a likely level of coal development but, perhaps more importantly, to show the relationship among the critical variables and the sensitivity of the projection to changes in the variables. The information contained in Tables 1 and 2 (and additional tables in the Appendices) allows the reader to examine the effect of different assumptions concerning federal pollution control policy, rates of growth in electrical generation, rates of increase in electricity and gas prices, and alternative fuel mixes.

⁹See section "Alternative Scenarios" in Part I.

SUMMARY TABLE 1

COAL PRODUCTION IN THE NORTHERN GREAT PLAINS
 BASED ON CONSTANT GROWTH IN ELECTRICAL GENERATION
 AND THE 1980-BASED CONTRACT SHARE OF ALL COAL DEMAND

PART A: Coal Production Assuming that Coal-Fired Generation Maintains its Current Share of Electric Energy Production

Market Estimate	Growth in Electrical Production	1980 NGP Coal Share	(Millions of Tons)		
			1980	1985**	2000**
All FGD	1%	.88	136	108	126
	3%*	.77	136	137	214
	5%*	.67	136	173	360
Partial FGD	1%	.88	136	34	52
	3%	.77	136	63	140
	5%	.67	136	99	285

PART B: Coal Production Based on the Assumption that the Residual Share of the Fuel Mix within the NGP Market Area will be Filled by Coal-Fired Generation

Market Estimate	Growth in Electrical Production	1980 NGP Coal Share	(Millions of Tons)		
			1980	1985**	2000**
All FGD	1%	.99	136	25	37
	3%	.69	136	83	154
	5%	.52	136	154	335
Partial FGD	1%	.99	136	0	0
	3%	.69	136	20	91
	5%	.52	136	91	272

*Our "most likely" projections.

**The 1985 and 2000 estimates are based on what the 1980 share of coal-fired generation being supplied by NGP coal would be if 5% annual growth in consumption takes place between 1974 and 1980. See page 54 for further explanation.

SUMMARY TABLE 2

COAL PRODUCTION IN THE NORTHERN GREAT PLAINS
 BASED ON PRICE-SENSITIVE ESTIMATES OF GROWTH IN ELECTRICAL GENERATION
 AND THE 1980-BASED CONTRACT SHARE OF COAL DEMAND

Price-Sensitive Coal Production Assuming that Coal-Fired Generation Maintains its Current Share of Electric Energy Production

Market Estimate	Annual Rate of Price Increase (Electric, Gas)	1980 NGP Coal Share	(Millions of Tons)		
			1980	1985**	2000**
All FGD	0%, 0%	.63	136	171	266
	FPC, 3%*	.65	136	161	221
	3%, 5%*	.72	136	130	115
	5%, 7%	.78	136	109	66
Partial FGD	0%, 0%	.63	136	99	194
	FPC, 3%	.65	136	89	149
	3%, 5%	.72	136	58	43
	5%, 7%	.78	136	37	0

Price-Sensitive Coal Production Based on the Assumption that the Residual Share of the Fuel Mix within the NGP Market Area will be Filled by Coal-Fired Generation

Market Estimate	Annual Rate of Price Increase (Electric, Gas)	1980 NGP Coal Share	(Millions of Tons)		
			1980	1985**	2000**
All FGD	0%, 0%	.47	136	151	238
	FPC, 3%	.49	136	132	186
	3%, 5%	.60	136	72	38
	5%, 7%	.72	136	30	0
Partial FGD	0%, 0%	.47	136	92	178
	FPC, 3%	.49	136	73	126
	3%, 5%	.60	136	13	0
	5%, 7%	.72	136	0	0

*Our "most likely" projections.

**The 1985 and 2000 estimates are based on the 1980 contract level for the (FPC, 3%) price increase permutation. See page 54 for further explanation.

SUMMARY TABLE 3

NGP COAL DEMAND FOR REPLACEMENT OF NATURAL GAS
BY COAL GASIFICATION AND DIRECT COMBUSTION OF COAL AS A BOILER FUEL

Coal Gasification Plants in the Northern Great Plains

	<u>1980</u>	<u>1985</u>	<u>2000</u>
"Most likely"	0	0	0
Low	0	0	0
High	0	3	3

Note: All plants rated at 250 MM Scf/day. One plant each will be located in Montana, Wyoming, and North Dakota in the high estimates.

Coal Requirements for Gasification Plants in the Northern Great Plains

	(Million Tons per Year)		
	<u>1980</u>	<u>1985</u>	<u>2000</u>
"Most likely"	0	0	0
Low	0	0	0
High	0	22.5	22.5

Note: Each plant requires 7.5×10^6 tons per plant-year of operation.

Consumption of NGP Coal as a Boiler Fuel to Replace Natural Gas

	(Million Tons per Year)		
	<u>1980</u>	<u>1985</u>	<u>2000</u>
"Most likely"	0	0	0
Low	0	0	0
High	0	16-31	33-63

SUMMARY TABLE 4

ALLOCATION OF NGP COAL PRODUCTION BY STATE
 BASED ON THE ASSUMPTION OF CONSTANT ELECTRICAL GENERATION GROWTH
 AND THE 1980-BASED CONTRACT SHARE OF COAL PRODUCTION

Market Estimate	Growth in Electrical Consumption	(Millions of Tons)		
		1980	1985	2000
All FGD				
Montana (27.6%)	1%	38	30	35
	3%	38	38	59
	5%	38	48	99
Wyoming (62.1%)	1%	84	67	78
	3%	84	85	133
	5%	84	107	223
North Dakota (10.3%)	1%	14	11	13
	3%	14	14	22
	5%	14	18	37
Partial FGD				
Montana (27.6%)	1%	38	9	14
	3%	38	17	39
	5%	38	27	79
Wyoming (62.1%)	1%	84	21	32
	3%	84	39	87
	5%	84	61	177
North Dakota (10.3%)	1%	14	3	5
	3%	14	6	14
	5%	14	10	29

SUMMARY TABLE 5

ALLOCATION OF NGP COAL PRODUCTION BY STATE
 BASED ON A PRICE-SENSITIVE ESTIMATE OF ELECTRICAL GENERATION GROWTH
 AND THE 1980-CONTRACT SHARE OF COAL PRODUCTION

Market Estimate	Annual Rate of Price Increase (Electric, Gas)	(Millions of Tons)		
		1980	1985	2000
All FGD				
Montana (27.6%)	0%, 0%	38	47	73
	FPC, 3%	38	44	61
	3%, 5%	38	36	32
	5%, 7%	38	30	18
Wyoming (62.1%)	0%, 0%	84	106	165
	FPC, 3%	84	100	137
	3%, 5%	84	81	71
	5%, 7%	84	67	41
North Dakota (10.3%)	0%, 0%	14	18	27
	FPC, 3%	14	17	23
	3%, 5%	14	13	12
	5%, 7%	14	11	7
Partial FGD				
Montana (27.6%)	0%, 0%	38	27	53
	FPC, 3%	38	25	41
	3%, 5%	38	16	12
	5%, 7%	38	10	0
Wyoming (62.1%)	0%, 0%	84	62	120
	FPC, 3%	84	55	93
	3%, 5%	84	36	26
	5%, 7%	84	23	0
North Dakota (10.3%)	0%, 0%	14	10	20
	FPC, 3%	14	9	15
	3%, 5%	14	6	4
	5%, 7%	14	4	0

PART I

PROJECTED DEMAND FOR NORTHERN GREAT PLAINS COAL

- A. Electric Energy Demand and the Demand for Northern Great Plains Coal.
- B. Forecasting Coal Gasification Activity in the Northern Great Plains.
- C. Liquefaction, Fertilizer Production, and Other Uses for Northern Great Plains Coal.

PART I

PROJECTED DEMAND FOR NORTHERN GREAT PLAINS COAL

There are three major sources of demand for Northern Great Plains coal; one is a reality now, one is a looming potential, and the final source is just beginning to receive attention. Electric utilities now consume 60-70% of the nation's coal,¹ and almost 100% of the NGP coal goes to electric utilities. Another major potential demand for NGP coal is gasification of coal to produce synthetic natural gas. The final potential demand for NGP coal is for liquefaction, petrochemical production and the production of fertilizer from coal.

The first section of Part I will examine the demand derived from coal-fired generation, the second section will discuss the demand based on coal gasification, and the final section will very briefly discuss liquefaction, fertilizer production and other related processes.

A. Electric Energy Demand and the Demand for Northern Great Plains Coal

Introduction

The demand for Northern Great Plains coal for electrical generation depends on a broad range of political and economic variables. These include the enforcement of natural and sulfur oxide air pollution standards, the cost and effectiveness of sulfur removal technologies, the price and

¹FEA Project Independence Report (November, 1974) p. 289.

availability (geological and political) of natural gas and petroleum, the cost, reliability and acceptability of nuclear fueled electric generating plants, the institutional constraints on the development of coal, transportation and transmission costs, and the long-range responsiveness of electrical consumption to price changes. The effect of these and other critical parameters was analyzed through four methodological steps: (1) identification of the extent of the geographic market for NGP coal; (2) estimation of the demand for electricity in that market area open to NGP coal; (3) allocation of a share of total electrical generation within the market area to coal-fired facilities; and (4) estimation of the share of coal-fired generation that will be supplied by NGP coal. The assumptions concerning each of these elements are summarized below, along with our analysis. The reader interested in greater detail will find references to the original working papers in the discussion.

Defining the Market open to NGP Coal

The market for NGP coal depends upon its delivered cost to the user (including special capital investments in plant needed to allow the use of it) compared to the same costs of alternative fuels. The most important costs to be considered are mining costs, transportation costs, and costs of air pollution control. In Working Paper #3 we have developed a simple market definition model based primarily on the work of W.D. Watson.² We have updated the data and dropped complications Watson showed were unnecessary. The model simply seeks to define lines ("hypercircles")³

²W.D. Watson, Jr., "Costs of Air Pollution Control in the Coal-Fired Electric Power Industry," Quarterly Review of Economics and Business, Vol. 12, No. 3 (Autumn, 1972). The following discussion provides a summary of Working Paper #3.

³C.D. Hyson and W.P. Hyson, "The Economic Law of Market Areas," Quarterly Journal of Economics, Vol. 64, No. 2 (1950).

where the cost of using midwestern and NGP coal are equal (assuming coal is located at a point source). Since important determinants of this market are the sulfur pollution regulations which are actually enforced, we have assumed the following:

1. There are sufficient locations in the NGP market area where coal-fired plants can be located without violating federal ambient air standards.
2. There is sufficient coal in the Northern Great Plains with low enough sulfur content that it can be burned without flue gas desulfurization and not violate the new federal stationary source emissions standards for sulfur oxides.
3. Standards similar to federal air pollution standards are enforced by states.⁴

These assumptions mean that our market definition focuses only on federal stationary source emission standards; hence two projections are necessary: one for new sources (it must meet federal standards of 1.2 pounds of SO_2 per million BTU's of coal burned) and another for the retrofitting of old plants to meet state air pollution emission control regulations. Specific annual costs were calculated for three facets of electric power generation by a "typical" coal-fired plant. These are:

1. The cost of fuel delivered to the plant;
2. The cost of pollution control equipment (capital and operating costs); and
3. Additional construction costs for increased boiler size and larger coal handling and pulverizing facilities due to use of low-BTU western coals relative to the base rate of burning high-BTU midwestern coal.

⁴Supported by William Tomlinson, Working Paper #13.

It is assumed that all other costs of construction and operation of the generating unit are independent of its location and the type of coal burned.

The first category of costs depends, of course, on mine mouth coal prices and transportation costs. We compared three "point sources" of coal production: (a) the Powder River Basin (northern Wyoming); (b) Williston Basin (west-central North Dakota); and (c) central Illinois to determine the geographic market to the east and south of the NGP states (see Figures 1, 2, 3 and 4 following). The associated production prices were assumed to be \$10/ton for Illinois coal, \$2.50/ton for North Dakota lignite, and \$5-\$6/ton for Wyoming (and similar Montana) subbituminous coal.⁵ Transportation was assumed to be by rail, using \$.007/ton-rail mile in 1974 and \$.00836/ton-rail mile in 1980.⁶

Additional charges for pollution control equipment for midwestern coal and for increased construction costs associated with burning NGP coal are summarized in Table 6 on the following page.

The results of the analysis are summarized in Figures 1, 2, 3 and 4. Figures 1 and 2 demonstrate the hypercircle or market boundary for North Dakota lignite vs. Wyoming subbituminous and the latter vs. Illinois coal for new plants requiring lime/limestone scrubber systems. As shown, the eastern boundary of the NGP market extends through Illinois, Missouri, Arkansas and Louisiana. The market boundary vis-a-vis midwestern coal

⁵Heat content was assumed to be 11,500 BTU/lb., 6,800 BTU/lb., and 8,300 BTU/lb., respectively.

⁶Based on J.G. Asbury and K.W. Costello, Price and Availability of Western Coal in the Midwestern Electricity Market 1974-1982, Argonne National Laboratory (October, 1974).

TABLE 6

ADDITIONAL ANNUAL CHARGES FOR
POLLUTION CONTROL EQUIPMENT AND CONSTRUCTION

Coal Source	Capital Charges (\$/KW)	Additional Operating Charges (MLS/KWH)	Total Annualized Charges (MLS/KWH)
Figure 1: Illinois ¹	70.00	1.5	3.2
N. Dakota ⁶	100.00	0.0	2.4
Wyoming ⁴	20.00	0.0	.49
Figure 2: Illinois ²	90.00	1.5	4.0
Wyoming ⁵	20.00	0.0	.57
Figure 3: Illinois ³	8.00	.15	.38
Wyoming ⁵	20.00	0.0	.57

¹Midrange charge for lime/limestone scrubbing FGD system as reported by John McBride, Working Paper #8.

²EPA estimates an additional charge of \$19/KW for retrofitting a lime/limestone scrubbing FGD system.

³Midrange charge for SCS retrofit. (Air Quality and Stationary Source Emission Control, a Report by the Commission on Natural Resources, National Academy of Sciences, National Academy of Engineering, National Resource Council, prepared for the U.S. Senate Committee on Public Works, March, 1975.)

⁴EPA estimates an additional charge for using western coal relative to eastern coal of \$2-\$40/KW, averaging \$20/KW. Watson used \$4.2/KW (1967 dollars), calculated as 5-10% of boiler cost using \$160/KW total installed cost with 35% attributable to boilers and auxiliaries. Using a more recent figure of \$500/KW installed plant cost, this formula gives an additional charge for using western coal of \$8.75-\$17.5/KW. (Source: see 3 above.)

⁵See 4 above. Retrofit costs are likely to be higher, but no estimates of this increase are known.

⁶This value is an estimate; no recent estimates have been found. Watson uses \$40/KW (1967 dollars). Capital charges of \$110/KW and \$130/KW for Figure 1 (Wyoming coal price=\$5/ton) and for Figure 2 (Wyoming coal price=\$6/ton) respectively restrict the North Dakota lignite market to within North Dakota. A \$100/KW capital charge presumes that there is no North Dakota lignite that can meet federal new source air pollution emission regulations without flue gas desulfurization.

NEW PLANT : 1000 Mw, 7000 HRS/YR, 9203 BTU/KWH				
RAIL COSTS:				
	1974	= \$.007/railmile	= \$.009/airmile	
	1980	= \$.00836/railmile	= \$.0106/airmile	
COAL DATA :				
ILLINOIS	BTU/LB	\$/TON	\$/KW	MILLS/KWH
N. DAKOTA	11500	10.00	70.00	1.5
WYOMING	6000	2.50	100.00	0.0
	8300	5.00	20.00	0.0

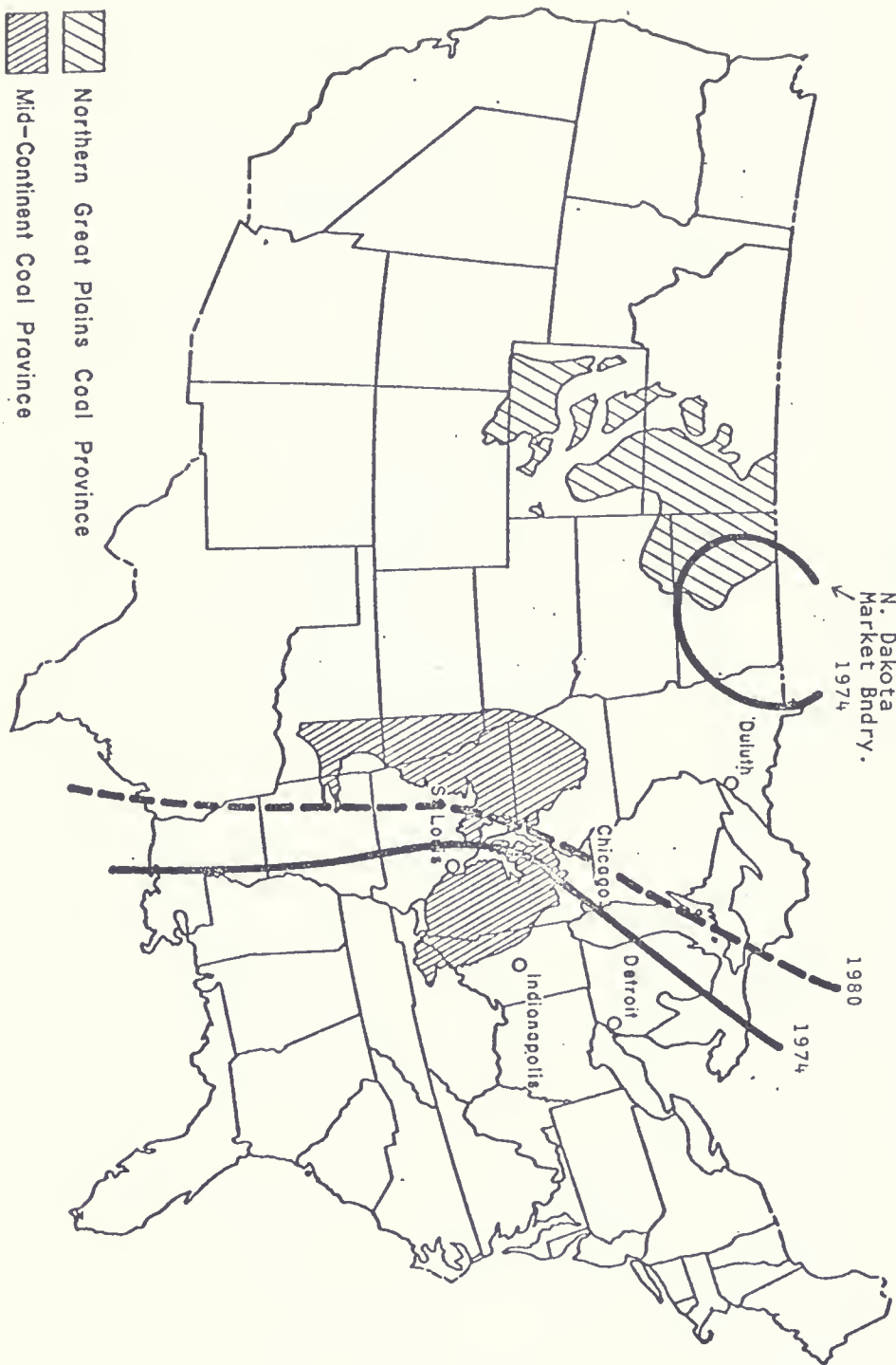


Figure 1. MARKET BOUNDARIES FOR ALTERNATIVE COAL SOURCES FOR NEW COAL-FIRED STEAM ELECTRIC GENERATING PLANTS (\$5 WYOMING COAL)

INPUT DATA

NEW PLANT : 1000 MW, 7000 HRS/YR, 9200 BTU/KWH
 RAIL COSTS: 1974 = \$.007/railmile = \$.009/airmile
 1930 = \$.00836/railmi = \$.0106/airmi

COAL DATA :	BTU/LB	\$/TON	\$/Kw	MILLS/KWH
ILLINOIS	11500	10.00	70.00	1.5
N. DAKOTA	6800	2.50	100.00	0.0
WYOMING	8300	6.00	20.00	0.0

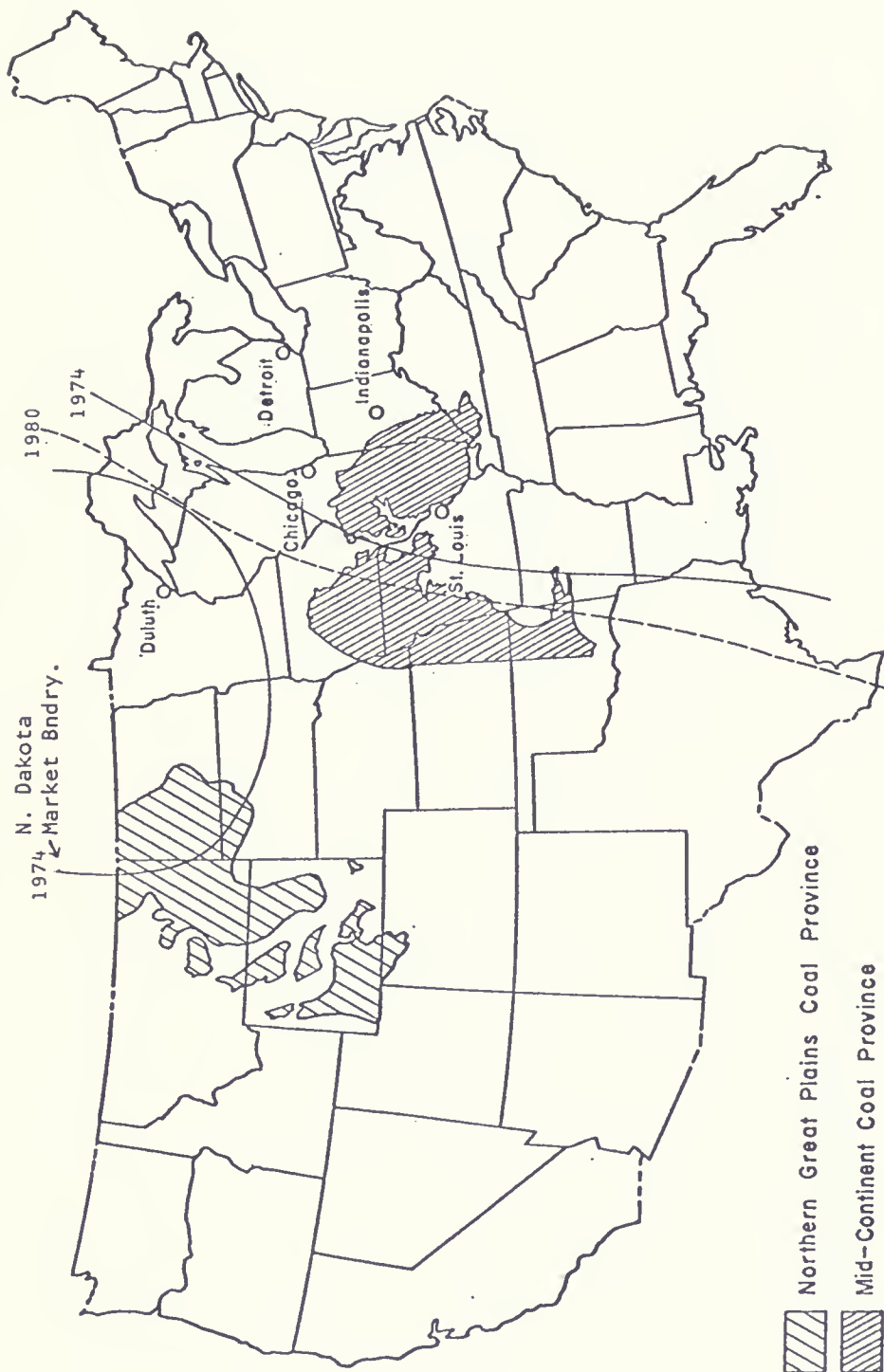


Figure 2. MARKET BOUNDARIES FOR ALTERNATIVE COAL SOURCES FOR NEW COAL-FIRED STEAM ELECTRIC GENERATING

PLANTS (\$6 WYOMING COAL)

INPUT DATA

OLD PLANT : 500 MW, 6000 HRS/YR, 10000 BTU/KWH
 RAIL COSTS: '1974'=\$.007/railmile=\$.009/airmile
 '1980'=\$.00836/railmi=\$.0106/airmi

COAL DATA :	BTU/LB	\$/TON	\$/KW	MILLS/KWH
ILLINOIS	11500	10.00	90.00	1.5
WYO.	8300	5.00	20.00	0.0
WYO.	8300	6.00	20.00	0.0

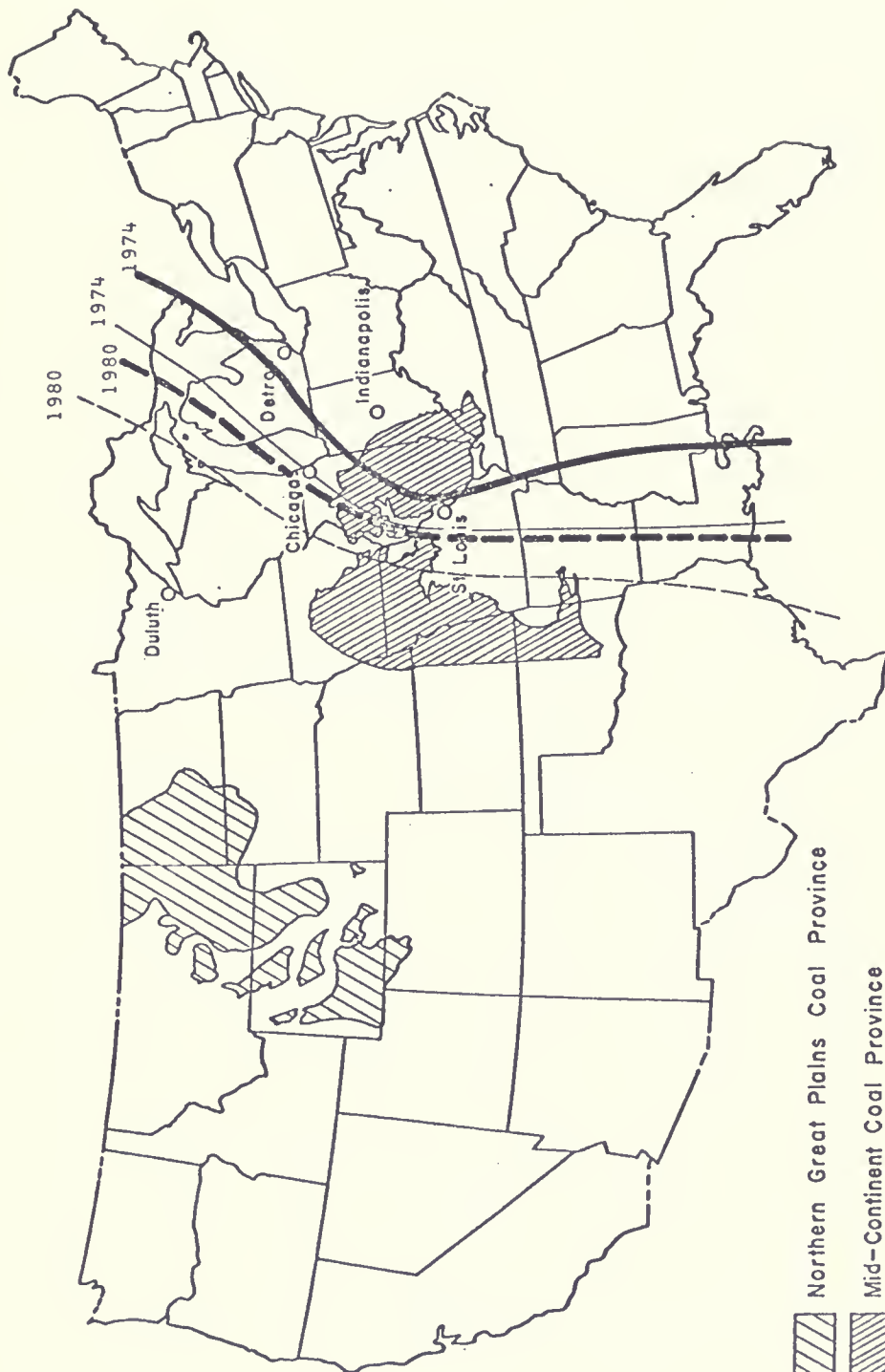


Figure 3. MARKET BOUNDARIES FOR ALTERNATIVE COAL SOURCES FOR EXISTING COAL-FIRED ELECTRIC GENERATING PLANTS WITH SCRUBBER RETROFIT REQUIRED

INPUT DATA

OLD PLANT : 500 MW, 6000 HRS/YR, 10000 BTU/KWH
 RAIL COSTS: '1974'=\$.007/railmile=\$.009/airmile
 '1980'=\$.00836/railmi=\$.0106/airmi

COAL DATA :					
1 BTU/LB = \$.00836/airmi = \$.0106/airmi					
ILLINOIS	BTU/LB	\$/TON	\$/KW	MILLS/KWH	
WYO.	11500	10.00	8.00	0.15	
WYO.	8300	5.00	20.00	0.0	
WYO.	8300	6.00	20.00	0.0	

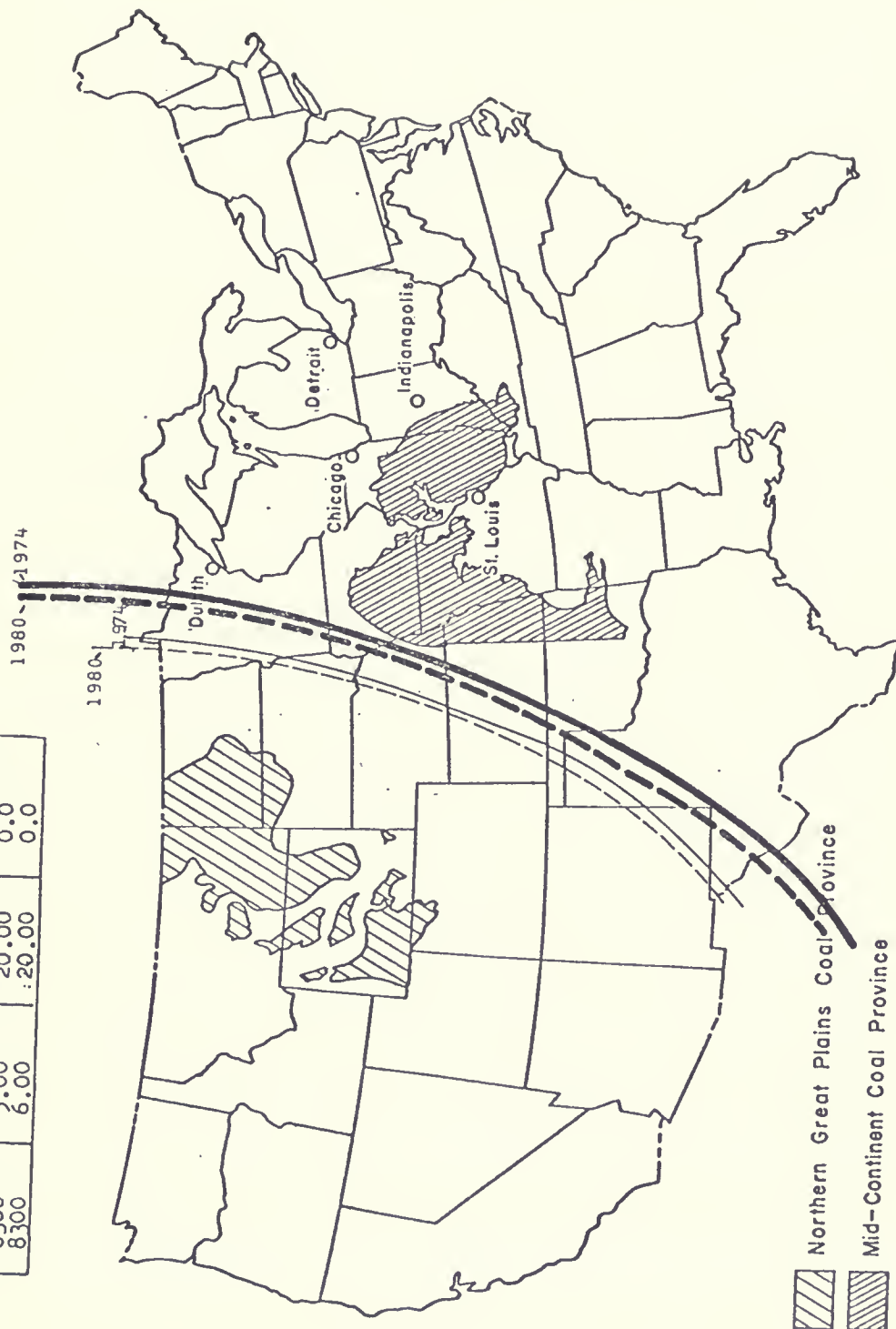


Figure 4. MARKET BOUNDARIES FOR ALTERNATIVE COAL SOURCES FOR EXISTING COAL-FIRED ELECTRIC GENERATING PLANTS WITH SUPPLEMENTAL CONTROL SYSTEMS

is not extremely sensitive to alternative transportation rates (the 1974 vs. 1980 lines) or alternative relative coal production prices (\$5 Wyoming coal in Figure 1, \$6 in Figure 2).⁷

Figures 3 and 4 demonstrate the effect on the market boundary of alternative pollution standards for retrofitting existing plants. When stringent controls requiring lime/limestone scrubbers are enforced, the market again extends well into Illinois. However, when SCS are permitted, the market boundary shrinks back to Minnesota and eastern Nebraska, as shown.

The market for NGP coal is primarily sensitive to alternative pollution control standards. Therefore, in our analysis we have defined an expanded All FGD market (corresponding to the case where scrubbers are required) to include the following 21 states: Montana, Wyoming, Washington, Oregon, Idaho, Colorado, Iowa, South Dakota, North Dakota, Minnesota, Nebraska, Illinois, Missouri, Wisconsin, Arkansas, Louisiana, Kansas, Oklahoma, Texas, Indiana, and Michigan. Our residual All SCS market (where ICS/tall stack systems are permitted) includes 13 states, the following eight states being omitted from the preceding list: Iowa, Illinois, Missouri, Wisconsin, Arkansas, Louisiana, Indiana, and Michigan. As a check on our assumption that state and federal air pollution standards would be similar, federal and state emission and ambient air pollution standards were compared in these eight "swing" states. We reason that the other 13 states will be in the NGP coal market regardless of pollution standards. The results

⁷The latter change does substantially increase the market for North Dakota lignite, but this is merely a redistribution within the NGP market area.

are summarized in Tables 7 and 8.⁸ As can be seen, state and federal standards are nearly identical in the "swing" states, suggesting that our assumption is valid. It should be noted that the state of Wyoming does have sulfur oxide air pollution emission standards which are much more stringent than present federal new source emission standards. If these standards are upheld, coal-fired electric power generation in Wyoming will be limited. Generation which would have occurred in Wyoming would be translocated to some other state. However, no translocation outside of the NGP coal market area is expected. Wyoming's intrastate coal consumption will be decreased in this circumstance but Wyoming coal exports could be higher than currently expected because of the translocation.

The model developed previously only describes a market boundary vis-a-vis midwestern coal. A market boundary between Northern Great Plains and Southwestern (Arizona, Utah, New Mexico) coal was not determined. It is possible that there may be some overlap between the Northern Great Plains and Southwestern coal market areas in the Colorado, Texas, Louisiana area. Because of the limited extent of Southwestern coal reserves we assumed that there would not be a significant export of Southwestern coals to the east. The verification of this assumption requires further research. Our model also assumes minimum cost strategy. There are two major reasons this may not be appropriate: (1) Uncertainty. Given the uncertainty which electric utilities face about enforcement of deadlines in meeting pollution standards, the possibility of SCS being approved, the performance of FGD methods, the potential relaxation of standards, etc., they may use a non-minimum cost method so as to reduce the risk. This uncertainty, we assume, should disappear over the next two to three years as political decisions

⁸Based on William Tomlinson, Working Paper #13.

TABLE 7
COMPARISON OF FEDERAL EMISSION STANDARDS FOR NEW COAL FIRED POWERPLANTS
WITH NORTHERN GREAT PLAINS COAL MARKET AREA SINGING STATES STANDARDS
(Standards expressed as lbs/MM Btu total heat input)

STANDARDS	LOCATION								
	Arkansas	Illinois	Indiana	Iowa	Louisiana	Michigan	Missouri	Wisconsin	Federal
Sulfur Dioxide	1.20 <u>1/</u>	1.20 <u>2/</u>	1.20 <u>5/</u>	6.00 <u>8/</u>	2000 ppm <u>10/</u>	1.60 <u>12/</u>	1.17 <u>1/</u>	1.20 <u>15/</u>	1.20 <u>18/</u>
Particulates	0.10 <u>1/</u>	0.10 <u>3/</u>	0.10 <u>6/</u>	0.60 <u>9/</u>	0.60 <u>11/</u>	0.10 <u>13/</u>	0.10 <u>14/</u>	0.10 <u>16/</u>	0.10 <u>19/</u>
Nitrogen Oxides	0.70 <u>1/</u>	0.70 <u>4/</u>	0.70 <u>7/</u>	-----	-----	-----	-----	0.70 <u>17/</u>	0.70 <u>20/</u>

Footnotes

- 1/ Scrubber Developments in the West, Sondreal, E.A. and Tufte, P.H., p. 7, Table 5
2/ Rule 204(a) (1) Sulfur Standards and Limitations, Sulfur Dioxide Emission Standards and Limitations for New Fuel Combustion Emission Sources with Actual Heat Input Greater than 250 Million Btu/Hr. Solid Fuel Burned Exclusively
3/ Rule 203, Figure 2.3 Allowable Emissions from Solid Fuel Combustion Sources Outside Chicago MMA.
4/ Rule 207(a) (4) Nitrogen Oxide Emission Standards and Limitations, New Fuel Combustion Sources
5/ APC 13 (1) (a) Indiana Sulfur Dioxide Regulation, Maximum Allowable Sulfur Dioxide Emissions
6/ APC 4-R(3) Combustion for Indirect Heating
7/ APC 17(1) (a) (3) Maximum Allowable Nitrogen Oxide Emissions
8/ 4.3(3) (a) & (b) Sulfur Compounds
9/ 4.32(b) (3) Particulate Matter, Combustion for Indirect Heating
10/ 24.7.4 Emission Standards for Sulfur Oxides, Existing Sources
11/ 21.3 Emission of Particulate Matter from Fuel Burning Equipment, Emission Limitations
12/ R 336.49 Table 4, Emission of Sulfur Dioxide from Power Plants (Standard applied may be more stringent based on case by case review of source by the Commission.)
13/ Personal Communications, Michigan Department of Natural Resources, Aug. 29, 1975
14/ Missouri Regulation S-VI E. (2) (e) Maximum Allowable Emissions of Particulate Matter from Fuel Burning Equipment Used for Indirect Heating
15/ HR 154.12 (2) (2) Control of Sulfur Emissions, Sulfur Limitations
16/ HR 154.11 (5) (a) (2) Control of Particulate Emissions, Particulate Emission Limits for Fuel Burning Installations
17/ HR 154.15 (2) (a) (3) Control of Nitrogen Oxide Limitations
18/ 39 FR 20790 § 60.43 Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators, Standard for Sulfur Dioxide
19/ 39 FR 20790 § 60.42 Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators, Standard for Particulate Matter.
20/ 40 FR 2803 § 60.44 Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators, Standard for Nitrogen Oxides

COMPARISON OF FEDERAL AMBIENT AIR STANDARDS
WITH NORTHERN GREAT PLAINS COAL MARKET AREA SMILING STATES STANDARDS

STANDARDS	LOCATION						
	Arkansas	Illinois	Indiana	Iowa	Louisiana	Michigan	Missouri
Sulfur Dioxide	.20 ppm 30 min. ave.	•80ug/m ³ annual •365ug/m ³ 24 hr. max. •1300ug/m ³ 3 hr. max. 3/	•80ug/m ³ annual •365ug/m ³ 24 hr. max. •60ug/m ³ annual •260ug/m ³ 24 hr. max. •1100ug/m ³ 1 hr. max. 5/	same as federal 9/	•80ug/m ³ 10/ annual •365ug/m ³ 24 hr. max. •60ug/m ³ annual •260ug/m ³ 24 hr. max. •1300ug/m ³ 3 hr. max.	same as 11/ federal	•25ppm 1 hr. •07ppm 24 hr. 12/
Particulates	75ug/m ³ 2/ 24 hr. max. 150ug/m ³ 30 min. max.	•75ug/m ³ annual •260ug/m ³ 24 hr. max. •60ug/m ³ annual •150ug/m ³ 24 hr. max. 5/	•75ug/m ³ annual •260ug/m ³ 24 hr. max. •60ug/m ³ annual •150ug/m ³ 24 hr. max. 7/	same as federal 9/	•75ug/m ³ 10/ annual •260ug/m ³ 24 hr. max. •60ug/m ³ annual •150ug/m ³ 24 hr. max.	same as 11/ federal	80ug/m ³ 13/ 6 month mean 200ug/m ³ 2 hr. max.
Nitrogen Oxides	-----	•100ug/m ³ annual 5/	•100ug/m ³ annual 8/	same as federal 9/	•100ug/m ³ 10/ annual	same as 11/ federal	-----

* Primary Standards

** Secondary Standards

Footnotes

- 1/ Section 8(a) Arkansas Air Pollution Control Code, Emission of Sulfur Compounds
 2/ Section 7(a)(1) Arkansas Air Pollution Control Code, Emission of Particulate Matter from Equipment
 3/ Personal Communications, Illinois Environmental Protection Agency
 4/ Rule 307, Illinois Air Quality Standards, Particulates
 5/ Rule 311, Illinois Air Quality Standards, Nitrogen Dioxide
 6/ APC 14 (1) Indiana Ambient Air Quality, Sulfur Dioxide
 7/ APC 14 (2) Indiana Ambient Air Quality, Suspended Particulate
 8/ APC 14 (6) Indiana Ambient Air Quality, Nitrogen Dioxide
 9/ 10.1(45) Iowa Ambient Air Quality Standards, State-wide standards
 10/ 8.4, Table 1 and 1a, Louisiana Air Pollution Control Regulations, Ambient Air Quality Standards
 11/ Personal Communications, Michigan Department of Natural Resources
 12/ S-X (F) Missouri Regulation, Restriction on Emission of Sulfur Compounds, Emission of Sulfur Compounds in Certain Amount and Manner Restricted
 13/ S-VII (E) Missouri Regulations, Restriction of Particulate Matter from Becoming Airborne, Property-line Standard Limitations for Particulate Matter becoming Airborne
 14/ NR 155.03(1) Wisconsin Ambient Air Quality Standards, Air Standards, Sulfur Oxides
 15/ NR 155.03(2) Wisconsin Ambient Air Quality Standards, Air Standards, Suspended Particulate Matter
 16/ NR 155.03(6) Wisconsin Ambient Air Quality Standards, Air Standards, Nitrogen Dioxide
 17/ 450.4 6 : 50.5 National Primary and Secondary Ambient Air Standards for Sulfur Oxides
 18/ 450.6 4 : 50.7 National Primary and Secondary Ambient Air Quality Standards for Particulate Matter
 19/ 450.14 National Primary and Secondary Ambient Air Quality Standards for Nitrogen Dioxide

are made, court decisions are reached, and data on technical performance of equipment become available. (2) Industrial Structure. We know little or nothing about corporate strategy for coal development. The same companies which own oil fields and uranium deposits also own coal in Appalachia, the Midwest, and the NGP states. Their long-run profit maximizing strategy is unknown. Are there forces which will lead them to restrict temporarily coal development on properties they own in Appalachia or the Midwest in favor of NGP development? (For example, are they cornering some part of the NGP deposits in an institutional environment where they must mine if they lease?) Or are the pressures the opposite?

However, empirical evidence on recent past and current decisions by utilities seems to support our cost-minimizing model. Our compilation of NGP coal contracts to 1980 by state of destination⁹ coincides with our 21-state All FGD market area, with the exception of Washington. The latter should clearly be included in the market area, based on current proposals for mine mouth plants to transmit energy to the Pacific Northwest. This evidence suggests that utilities expect scrubbers rather than supplementary control systems to be required. This, in fact, is federal policy,¹⁰ obviously subject to change. The uncertainty concerning future policy is suggested by the fact that the Federal Energy Administration currently advocates SCS for existing electric power plants, while the Environmental Protection Agency is still advocating scrubbers as a permanent control strategy.¹¹

⁹William Tomlinson, Working Paper #4.

¹⁰Based on the Clean Air Act of 1970 and the Energy Supply and Environment Coordinating Act of 1974.

¹¹Discussed more fully in John McBride, Working Paper #11.

To conclude, the market area where the NGP is the least cost source for new coal-fired generation facilities includes 21 states in the Pacific Northwest, the Great Plains and the Midwest. This is based on the assumption, which appears virtually certain, that scrubbers will be required on new plants. For existing plants, if lime/limestone scrubber systems are required, the same 21-state All FGD market applies. However, if Supplementary Control Systems are permitted for existing plants, which is a possibility, high-sulfur midwestern coal pollution control costs decline substantially. In such a case, NGP coal would be competitive in the smaller 13-state "Partial FGD" market area.

In making actual projections based on this market area, the All FGD market estimates in Appendices I and II are based on the assumption that scrubbers will be required on both new and existing electric generating plants in the expanded 21-state market area. The residual Partial FGD market estimates are based on permitting SCS for all existing plants but requiring new plants in the 21-state market area to operate scrubber systems.

Electrical Energy Demand in the NGP Coal Market Area

Having defined the market for NGP coal, the next methodological step was to estimate future electrical energy demand in this market area. The following discussion summarizes a more extensive survey in Working Papers #1 and #12.¹²

¹²Thomas Power, Working Paper #1; John Duffield and Terry Wheeling, Working Paper #12.

Survey of Electric Consumption Projections

Until recently energy projections were based on the extension of historical trends (population, local economic activity, appliance purchasing and use, etc.) with ad hoc judgmental adjustments made to take into account expected changes in these trends. There usually was no systematic procedure or formal model. Public utility projections are a good example of this type of projection. Combining an accurate feeling for developing trends in the regional economy with the experience of several decades of a nearly constant rate of growth in demand (growing at approximately 7% annually, doubling every 10 years), utilities projected consumption on a very informal basis. This is not to say that the utilities' projections were mere guesswork. Very detailed analyses of demographic, economic, and consumption trends were made of particular small areas to determine what transmission and distribution equipment would be needed in the future in those areas. But no consistent, overall methodology guided the projections for the entire system. These estimates by the individual utilities, the electric power company 10-year plans, are compiled by the Federal Power Commission by region (National Electric Reliability Councils). A recent summary¹³ by the FPC projects generation to grow at nearly the historical rate: 7.91% 1974-1980, 6.44% 1980-1985, and 5.69% 1985-2000. With minor modifications, the FPC projections have been the basis of the electrical sector forecasts in several recent influential federal studies: Dupree and West, U.S. Energy Through the Year 2000 (Department of the Interior, 1972), and the Northern Great Plains Resources Program, National and Regional Energy Considerations Work Group

¹³Federal Power Commission, National Power Survey, the Report of the Technical Advisory Committee on Fuel (draft), (September, 1974), pp. 67-77.

Report (discussion draft, February, 1974). The basis for the credibility of these projections lies in the fact that in the recent past projections of this type have been remarkably accurate. However, from an economist's standpoint these projections are naive, ignoring as they do the effect of price on quantity demanded. The recent decades of very high growth in electrical consumption have also been a period of rapidly declining real electrical prices due to technological advance in the utility sector. From 1935 to 1969, the real average price of electricity in the U.S. declined from 6.08¢/KWH to 1.40¢/KWH,¹⁴ or an average annual decline of 4.3%. This historical decline in the relative price of electricity would, of course, encourage increased consumption of electricity.

However, we now are entering a period when many of the variables affecting the consumption of electricity are departing from the historical pattern. In particular, increasing costs associated with environmental protection and decreasing fuel supplies, and a decrease in the rate of technological advance have halted the long-term decline in electrical prices. In 1970, for the first time since 1946, the deflated average price of electricity rose slightly (1.8%). For a recent 1-year period, February, 1974, to February, 1975, the deflated average price rose by 17.3%.¹⁵

In order to identify the effect of prices and other variables on consumption, econometric estimates of demand functions have been made. The sensitivity of consumption to changes in price (or changes in other

¹⁴Constant 1967 dollars. Derived from Edison Electric Institute, Year Book (1973), p. 53.

¹⁵Derived from FPC News, VIII, No. 24 (June 20, 1975), p. 46 and Federal Reserve Bank of St. Louis, Monetary Trends (August 20, 1975), p. 4.

variables) may be described in terms of elasticity, or the ratio of the percentage change in quantity demanded to the percentage change in price. Most estimates of the long run price elasticity of demand for electricity have been in the range of -1.00 to -2.00 (-1.00 suggests that a 1% increase in price causes a 1% decline in the quantity of electricity demanded). Income elasticities tend to be less than one. Table 9, reproduced from a recent survey article, summarizes the results of major studies in this area.

The estimated relationship between the consumption of electricity and variables such as the price of electricity, income, population, and the price of substitutes such as natural gas may, of course, be applied to project the future level of consumption of electricity. Several such projections of future electric energy consumption, along with the Federal Power Commission and Dupree and West projections, are summarized in Table 10.

The CMT estimates are from a study by Chapman, Mount and Tyrrell¹⁶ using class specific (residential, commercial, industrial) elasticities of electric demand as follows:¹⁷

CMT CLASS SPECIFIC ELASTICITY

Consumer Class	Elasticity				First Year Response (%)	Years for 50% Total Response
	Electricity Price	Population	Income	Gas Price		
Residential	-1.3	+0.9	+0.3	+0.15	10	8
Commercial	-1.5	+1.0	+0.9	+0.15	11	7
Industrial	-1.7	+1.1	+0.5	+0.15	11	7

¹⁶Chapman, Duane, et al., "Electric Demand Growth and the Energy Crisis," Science, Vol. 178, No. 4062 (November 17, 1972), p. 703.

¹⁷Op. cit., p. 705.

TABLE 9

PRICE AND INCOME ELASTICITIES OF ELECTRICITY

Demand Summary of Econometric Estimates

Type of Demand	Type of Price	Price Elasticity		Income Elasticity		Type of Data
		Short run	Long run	Short run	Long run	
<u>Residential</u>						
Houthakker	M	-0.89	NE	1.16	NE	CS: Cities (U.K.)
Fisher & Kaysen	A	≈ -0.15	≈ 0	≈ 0.10	Small	CS-TS: States
Houthakker & Taylor	A	-0.13	-0.89	0.13	1.94	TS: Aggregate U.S.
Wilson	A*	NE	-2.00	NE	≈ 0	CS: SMSA's
Mount, Chapman & Tyrrell	A	-0.14	-1.20	0.02	0.20	CS-TS: States
Anderson	A*	NE	-1.12	NE	0.80	CS: States
Lyman	A	(≈ -0.90)		(≈ -0.20)		CS-TS: Areas Served by Utilities
Houthakker, Verleger & Sheehan	M	-0.90	-1.02	0.14	1.64	CS-TS: States
<u>Commercial</u>						
Mount, Chapman & Tyrrell	A	-0.17	-1.36	0.11	0.86	CS-TS: States
Lyman	A	(≈ -2.10)				CS-TS: Areas Served by Utilities
<u>Industrial</u>						
Fisher & Kaysen	A	NE	≈ -1.25			CS: States
Baxter & Rees	A	NE	≈ -1.50			TS: Industries (U.K.)
Anderson	A	NE	-1.94			CS: States
Mount, Chapman & Tyrrell	A	-0.022	-1.82			CS-TS: States
Lyman	A	(-1.40)				CS-TS: Areas Served by Utilities

Note:

NE: Not estimated.
 CS: Cross-section.
 TS: Time-series.
 M: Marginal Price.

A: Ex post average price.
 A*: Average Price for a fixed amount of electricity consumed per month.

Source: L.D. Taylor, "The Demand for Electricity: A Survey," Bell Journal of Economics and Management Science, Vol. 6, No. 1 (Spring, 1975), p. 101.

TABLE 10

ALTERNATIVE FORECASTS OF U.S. ELECTRICITY CONSUMPTION[†]
(Trillion Kilowatt Hours)

Projection [*]	1970	1975	1980	1985	1990	2000
Cornell-NSF	1.57	2.15	2.92	3.96	5.38	10.25
CMT - High	1.53	2.14	3.05	----	5.66	9.89
- Medium	1.53	1.98	2.38	----	3.01	3.45
- Low	1.53	1.88	2.07	----	2.11	2.01
DW	1.53	2.13	3.00	4.14	----	9.01
FPC	1.53	----	3.07	----	5.83	----
HJ	1.53	1.94	2.59	3.35	----	6.98
NPC	1.59	2.29	3.29	4.54	----	----

*Cornell NSF is Cornell National Science Foundation Workshop; CMT is Chapman, Mount and Tyrrell; DW is Dupree and West; FPC is Federal Power Commission; HJ is Hudson-Jorgenson; NPC is National Petroleum Council.

Sources: Cornell NSF, FPC, NPC forecasts are given in Chapman, Mount and Tyrrell (1972), Table 1, Page 3. The CMT "low" forecast assumes that the real electricity price doubles by 2000. The "medium" forecast corresponds to the FPC estimates of a 19% real price increase over 1970-1990. The "high" forecast corresponds to a 24% real price decline over 1970-1980 and a 12% decline over each of the 1980-1990 and 1990-2000 intervals.

DERIVED RATES OF GROWTH OF ELECTRIC CONSUMPTION

Projection	1970-1980	1980-1990	1985-2000	1990-2000
Cornell-NSF	6.4	6.3	---	6.7
CMT - High	7.1	6.4	---	5.7
- Medium	4.5	2.4	---	1.4
- Low	3.1	.2	---	-0.5
DW	6.9	---	5.3	---
FPC	7.2	6.6	---	---
HJ	5.4	---	5.0	---
NPC	7.5	---	---	---

[†]Reproduced from Edward Hudson and Dale Jorgenson, "U.S. Energy Policy and Economic Growth," Bell Journal of Economics and Management Science, Vol. 5, No. 2 (Autumn, 1974) p. 461. Growth rates are derived.

The CMT-high projection was included to illustrate the real price declines necessary to duplicate the high growth FPC estimates. They found that price declines of 24% for 1970-1980 and 12% each decade thereafter would be necessary to reproduce the FPC estimate. The CMT-medium projection is based on the FPC estimate of price increases of a total of 19% between 1970 and 1980 (.87% annually) and the low projection assumes that real electric prices double by the year 2000 (2.33% annual increase). The HJ or Hudson-Jorgenson estimate is based on a more complex econometric model in which price is an endogenous variable.¹⁸ They project that real electric prices will fall between 1970 and 2000 from 2.12¢/KWH to 2.02¢/KWH due to increased productivity in the electric utility industry.

Another price-sensitive estimate, not compared in Table 5, is found in the FEA Project Independence Report. They project a high (6.5%) annual growth in electric consumption between 1973-1985. This high growth projection is primarily due to the choice of a very low price elasticity of demand (-.42) and a very high income elasticity (1.90).¹⁹ The latter is higher by a factor of two than most estimates, and the former is approximately one-half that of other studies. The combination of these two assumptions is enough to smother the impact of rising energy prices. Beyond 1985, the Project Independence Report projects a drop to a 2.0% growth rate in the "Base Case" and a 2.65% rate in the "Conservation with Major Shift to Electric Power" case.²⁰

¹⁸Discussed more fully in Thomas Power, Working Paper #1, pp. 44-49, along with a similar study by J.M. Griffin, "The Effects of Higher Prices on Electricity Consumption," Bell Journal of Economics and Management Science, Vol. 5, No. 2 (Autumn, 1974) p. 515.

¹⁹FEA, Project Independence Report (November, 1974), p. 56 of the Appendix.

²⁰Op. cit., pp. 433-434. Discussed more fully in Thomas Power, Working Paper #1, pp. 14-27.

Still another method of projecting demand is the appliance saturation model. If one is willing to assume that the next 25 years are not likely to see the development of new, widely used, electric energy intensive appliances (such as electric cars), one can study the growth in the commercial and residential demand for electric energy in two parts: (1) the increase or decrease in electric energy use by a particular appliance; and (2) the increase in the number of homes using that appliance (its increasing saturation).

This last consideration by itself suggests a slowing of the rate of growth of electric demand as appliances which are heavy users of electric energy (color TV, air conditioning, modern lighting, electric space heating) reach total saturation. Several regional studies using this methodology suggest future growth rates of 2-3%.²¹

In conclusion, estimates of near future electrical demand growth range from 3-7% annual increase while long-term growth estimates vary from a projected slight decline to a 6% annual increase. The estimates differ according to the model employed and assumptions concerning future values of key parameters such as price.

²¹Walter Butcher and George Hinman, Guidelines for a Northwest Energy Policy, Phase 2: Analysis of Energy Policies for 1980 (Pullman, WA: Washington State University, Environmental Research Center, revised September, 1974) p. 11; and G. Diamonte, "A Growth Projection for Electric Demand in San Diego County to the End of the Century," Report EC-E-1, University of California, San Diego, August, 1973, in S.S. Penner and L. Icerman, Energy (Reading, MA: Addison Wesley, 1974). These studies are discussed in more detail in Hinman, et al., Part II, and in Thomas Power, Working Paper #1, pp. 53-55.

Montana University Coal Demand Study

Two approaches to the estimation of the demand for electric energy in the NGP market area were used in this study. While the preceding survey demonstrated a wide range in the estimates of future growth, all studies which take into account the price sensitivity of demand show a decline from the historical 7% growth rate. The highest projections (technologically optimistic with respect to the efficiency of electrical generation) indicate about a 5% annual increase. The lowest show a 0-1% growth rate. As one approach we chose 1-5% per year growth in electrical consumption to bracket actual consumption, with 3% the most likely, and applied this growth uniformly to existing consumption in the NGP market area. This projection is tabulated in Table A, Appendix II, for both the All FGD and All SCS market areas.

Our second approach was to provide our own price-sensitive²² estimate for the 21-state market area, based on an econometric model developed by L.D. Chapman, et al.²³ This model was developed from annual observations of data from 47 states (North and South Carolina were combined) from 1947 to 1970.²⁴

²²What the appropriate measure of "the price" of electricity is has been widely debated by economists. Chapman uses an "average" price. This would bias the estimates of elasticities if he were estimating an individual household's demand. He, however, was aggregating the data on thousands of households and in this situation the problems associated with representing a declining block structure of rates by a single average price are significantly reduced.

²³T.D. Mount, L.D. Chapman and T.J. Tyrrell, Electricity Demand in the U.S.: An Econometric Analysis, ORNL-NSF-EP-49 (Oak Ridge, TN; Oak Ridge National Laboratory, June, 1973).

²⁴Our attempts to use a similar price-sensitive model for a 15-year time series on an individual state were fruitless. Generally only lagged demand had a significant coefficient. Mount et al. report this to be the finding of most researchers working with a single time series. Hence, the need for cross-sectional data is demonstrated.

The basic form of the model is given by:

$$Q_{it} = A Q_{it-1}^{\lambda} V_{1it}^{\beta_1} \dots V_{Nit}^{\beta_N} e^{\gamma_1/V_{1it}} \dots e^{\gamma_N/V_{Nit}},$$

or in logarithmic form:

$$\log Q_{it} = \alpha + \lambda \log Q_{it-1} + \sum_{n=1}^N \beta_n \log V_{nit} + \sum_{n=1}^N \gamma_n \frac{1}{V_{nit}}$$

where:

i is the i^{th} state;

t is the t^{th} year;

Q is the quantity of electricity demanded;

V_n is the level of the n^{th} causal factor; and

$A, \lambda, \beta_1 \dots \beta_n, \gamma_1 \dots \gamma_n$ and α are unknown parameters.

The short run elasticity of the n^{th} causal factor is:

$$[\beta_n - (\gamma_n/V_n)]$$

and the long run elasticity is:

$$[\beta_n - (\gamma_n/V_n)]/(1 - \lambda).$$

When γ_n is constrained to be zero, then the model is termed a Constant Elasticity Model (CEM); if not, the model is termed a Variable Elasticity Model (VEM).²⁵ In addition, Chapman uses two different techniques for estimating the unknown parameters in the logarithmic form of the equation -- Ordinary Least-Squares (OLS) and Instrumental Variables (IV).²⁶ The estimated parameters for three of the models and estimation techniques investigated by Chapman are given in Table 11. These are designated in

²⁵"Variable" elasticity means that the sensitivity of electric consumption to a change in one of the explanatory variables is not constrained to be the same for all values of that variable: it can change with the value of the variable. For instance, the sensitivity of consumption of electricity to changes in income may depend on a person's real income.

²⁶Since one of the independent variables in the estimating equation is the value of the dependent variable lagged one year, a serious problem with autocorrelation in the residuals is possible. The instrumental variable technique attempts to avoid this problem.

PARAMETER ESTIMATES FOR THE CONSTANT AND VARIABLE ELASTICITY MODELS

Explanatory Factor	Units of Measurement	Parameter Estimated	RESIDENTIAL			COMMERCIAL			INDUSTRIAL		
			Constant	Variable Elasticity (Model A)	IV	Constant	Variable Elasticity (Model A)	IV	Constant	Variable Elasticity (Model A)	IV
1. Lagged demand	Million kilowatt hours	λ	.8859 (136.5)	.8837 (119.2)	.7177 (35.0)	.8735 (75.7)	.8724 (75.7)	.1843 (2.4)	.8869 (79.9)	.8765 (76.5)	.2157 (2.7)
2. Population	Thousands	β	.1075 (17.0)	.1172 (15.5)	.2703 (15.5)	.1244 (10.6)	.1333 (10.2)	.8105 (10.4)	.1237 (8.5)	.1220 (7.5)	.7970 (9.1)
3. Income	Thousand dollars per capita (deflated)	γ	.0000 ---	.97821 (5.3)	.83737 (2.5)	.0000 ---	.105007 (1.6)	.32.9935 (2.4)	.0000 ---	-.11.7364 (1.0)	-.97.7104 (5.5)
4. Price of Electricity	Mills per kilowatt hour (deflated)	β	.0343 (4.2)	.0195 (0.6)	.0000 ---	.1011 (5.3)	.1486 (2.5)	.6825 (4.9)	.0817 (3.3)	.0000 ---	.0000 ---
		γ	.0000 ---	-.0139 (0.2)	-.2246 (6.8)	.0000 ---	.1432 (1.0)	-.1387 (0.5)	.0000 ---	-.2358 (5.6)	-.1.8921 (8.0)
		β	-.1385 (12.5)	-.1552 (7.7)	-.4524 (10.4)	-.2030 (9.6)	-.2925 (6.2)	-.1.3242 (8.9)	-.2021 (8.1)	-.3097 (8.9)	-.1.8867 (9.1)
5. Price of Gas	Dollars per thousand therms (deflated)	β	.0238 (6.7)	.0225 (6.2)	.0370 (7.7)	.0068 (1.0)	.0082 (1.1)	.0305 (2.0)	.0000 ---	.0000 ---	.0475 (2.4)
6. Price of Appliances	Price index (deflated)	β	-.0408 (2.4)	-.0486 (2.5)	-.2094 (7.5)	.0000 ---	.0000 ---	.0000 ---	.0000 ---	.0000 ---	.0000 ---
7. Region	North East	α	.4620	.4986	1.7699	.5960	.8115	3.4981	.4897	1.1280	6.4039
	Mid Atlantic	α	.4612	.4917	1.7564	.5897	.7958	3.5180	.4363	1.0766	6.0087
	East North Central	α	.4802	.5117	1.7818	.5930	.8021	3.5006	.4814	1.1190	6.2585
	West North Central	α	.5056	.5404	1.8319	.6180	.8340	3.6629	.4374	1.0640	5.8895
	South Atlantic	α	.4858	.5181	1.7669	.6088	.8178	3.5222	.4764	1.1052	6.1519
	East South Central	α	.4844	.5150	1.7443	.5619	.7692	3.3090	.4995	1.1335	6.3657
	West South Central	α	.5175	.5492	1.8190	.6381	.8484	3.6860	.4639	1.0876	6.0289
	Mountain	α	.4837	.5151	1.7641	.6392	.8493	3.6691	.4635	1.0875	6.0307
	Pacific	α	.4679	.5020	1.7445	.5688	.7862	3.3586	.3586	1.0050	5.5643
Estimated Residual Variance			.001335	.001324	.002042	.006834	.006795	.029547	.022271	.022034	.090169
Sum of Squared Residuals			1.4229	1.4071	2.1725	7.2917	7.2295	31.4384	23.7852	23.5100	96.0305

* The constraint $\gamma = \beta$ is imposed for the industrial price of electricity in this model to ensure that the estimated price elasticity is negative for all observed price levels.

Source: Mount, T.D., Chapman, L.D., Tyrrell, T.J., Electricity Demand in the United States: An Econometric Analysis, ORNL-NSF-EP-49, 1973

the following as CEM/OLS, VEM/OLS and VEM/IV. Also shown are the explanatory variables used and the units of measurement.

Table 12, also reproduced from Chapman's study, shows the long run elasticities evaluated at 1971 values of the variables. For the CEM model, the mean level of the elasticity of demand for all states is -1.21 to -1.79 for electricity price, .30 to .80 for income, and .21 to .00 for the cross-price elasticity with respect to gas.

Chapman reports the coefficients λ , β_j , γ_j ($j=1 \dots 4$) on a state basis, but since the market area for NGP coal contains only a portion of these regions, we therefore attempted to fit Chapman's three models to individual states and made our projection on a state-by-state basis. For this, the coefficients λ , β_j , γ_j , for $j = 1$ to 4 (price of appliances was dropped from the models) were taken as reported by Chapman. The coefficient α , a shift parameter unassociated with any of the independent variables, was determined for each model for each class (Residential, Commercial, Industrial) within each state to give the best fit for the time period 1967 to 1973.

Specifically, α was chosen so that:

$$\sum_{t=1967}^{1973} (y_t - x_t - \alpha) = 0$$

where:

$$y_t = \ln Q_t$$

$$x_t = \lambda \ln Q_t + \sum_{j=1}^4 \beta_j \ln V_{jt} + \sum_{j=1}^4 \gamma_j / V_{jt}$$

TABLE 12
ESTIMATED LONG-RUN ELASTICITIES FOR THE DEMAND OF ELECTRICITY
(Evaluated at 1971 Factor Levels)

Class of Demand	Factor	Elasticity Model	Estimation Procedures	New York	Tennessee	Mean Level for All States
Residential	Population	Constant	OLS	.94	.94	.94
		Variable	OLS	1.00	.99	.99
			IV	.96	.95	.95
	Income	Constant	OLS	.30	.30	.30
		Variable	OLS	.19	.21	.20
			IV	.17	.25	.21
	Price of Electricity	Constant	OLS	-1.21	-1.21	-1.21
		Variable	OLS	-1.24	-1.10	-1.20
			IV	-1.34	-.96	-1.24
	Price of Gas	Constant	OLS	.21	.21	.21
		Variable	OLS	.19	.19	.19
			IV	.13	.13	.13
	Price of Appliances	Constant	OLS	-.36	-.36	-.36
		Variable	OLS	-.42	-.42	-.42
			IV	-.74	-.74	-.74
Commercial	Population	Constant	OLS	.98	.98	.98
		Variable	OLS	1.04	1.02	1.03
			IV	.99	.98	.98
	Income	Constant	OLS	.80	.80	.80
		Variable	OLS	.93	.81	.86
			IV	.87	.89	.88
	Price of Electricity	Constant	OLS	-1.60	-1.60	-1.60
		Variable	OLS	-1.65	-1.12	-1.36
			IV	-1.50	-1.40	-1.45
	Price of Gas	Constant	OLS	.05	.05	.05
		Variable	OLS	.06	.06	.06
			IV	.04	.04	.04
Industrial	Population	Constant	OLS	1.09	1.09	1.09
		Variable	OLS	.99	1.01	1.01
			IV	1.02	1.05	1.05
	Income	Constant	OLS	.72	.72	.72
		Variable	OLS	.40	.60	.51
			IV	.50	.76	.65
	Price of Electricity	Constant	OLS	-1.79	-1.79	-1.79
		Variable	OLS	-1.89	-1.53	-1.82
			IV	-1.81	-1.46	-1.74
	Price of Gas	Constant	OLS	.00	.00	.00
		Variable	OLS	.00	.00	.00
			IV	.06	.06	.06

Source: Mount, T.D., Chapman, L. D., Tyrrell, T.J.,
Electricity Demand in the United States: An
Econometric Analysis, ORNL- NSF- EP-49, 1973

Since two regions as used by Chapman were wholly contained within the All FGD market for NGP coal, the coefficient α was determined for these regions from our 7-year time series. These are compared to the α 's determined by Chapman in Table 13 based on his 23-year series. As can be seen, our estimates differ by less than 5%.

To compute the projected levels of electric energy demand for a given state and class, independent projections of the explanatory variables were obtained. The population and personal income estimates are based on the OBERS Projections, Series E.²⁷

Given the uncertainty surrounding the likely future levels of prices, three sets of annual growth rates in these prices were used. The low estimate for the price of electricity was based on the FPC region-specific projection²⁸ as follows:

West at	1.08% per year
West-Central at	.42% per year
South-Central at	.67% per year
East-Central at	1.02% per year

The associated natural gas price increase was set at 3%, based on an estimate by the M.I.T. Energy Laboratory for gas price increases under a "price control" situation.²⁹ The intermediate increase was set at 3%

²⁷1972 OBERS Projections, Series E, Volume 1 (Washington, DC: U.S. Water Resources Council, April, 1974).

²⁸Rate of price increase derived from FPC, 1970 National Power Survey.

²⁹Policy Study Group of the M.I.T. Energy Laboratory, "Energy Self-Sufficiency: An Economic Evaluation," Technology Review, LXXVI, No. 6 (May, 1974).

TABLE 13
COMPARISON OF COEFFICIENT ALPHA FOR REGIONAL DATA

A. West North Central Region

	Residential			Commercial			Industrial		
	CEM/OLS	VEM/OLS	VEM/IV	CEM/OLS	VEM/OLS	VEM/IV	CEM/OLS	VEM/OLS	VEM/IV
Chapman et al.	.5056	.5404	1.8319	.6180	.8340	3.6629	.4374	1.0640	5.8895
Wheeling-Duffield	.5040	.5286	1.8109	.5861	.7884	3.5133	.4322	1.0744	5.9549
Percent Difference*	-0.31	-2.18	-1.14	-5.16	-5.46	-4.08	-1.18	0.97	1.11

B. West South Central Region

	Residential			Commercial			Industrial		
	CEM/OLS	VEM/OLS	VEM/IV	CEM/OLS	VEM/OLS	VEM/IV	CEM/OLS	VEM/OLS	VEM/IV
Chapman et al.	.5175	.5492	1.8190	.6381	.8484	3.6860	.4639	1.0876	6.0289
Wheeling-Duffield	.5388	.5603	1.8416	.6155	.8248	3.6738	.4400	1.0802	5.9378
Percent Difference*	4.11	2.02	1.24	-3.54	-2.78	-0.33	-5.15	-0.68	-1.51

*Calculated as (Wheeling-Duffield minus Chapman)/Chapman.

for electrical and 5% for gas and the high at 5% and 7% annual increase for electricity and gas, respectively. These numbers reflect the range used in several recent studies.³⁰ The effect of constant prices (0% rate of growth) was also projected.

It is difficult to assess the reasonableness of the various price assumptions. Some weighing of technological advance (MHD, fluidized bed, combined cycles, standardization, etc.) against rising environmental control costs, rising fuel costs, decreasing utilization (peak load growth) and regulatory policy is necessary. As an example, the results of an econometric study by Paul MacAvoy showing the effect of alternative regulatory policy on natural gas prices is summarized in Table 14.³¹

TABLE 14

NATURAL GAS PRICES UNDER ALTERNATIVE REGULATORY ACTIONS³²

<u>Policy</u>	<u>Average Wholesale Price (¢/Mcf)</u>		<u>Annual Rate of Price Increase to 1980</u>
	<u>1972</u>	<u>1980</u>	
Cost of Service Regulation	33.6	48.0	4.49
Regulatory Status Quo	33.6	54.6	6.25
Deregulation	33.6	64.9	8.22

³⁰Duane Chapman, et al., "Electric Demand and Utility Capacity Planning," Cornell Agricultural Economics Staff Paper, No. 73-23 (November, 1973) and Duane Chapman and Timothy Mount, "Electric Demand and the Financial Problems of Electric Utilities," Cornell Agricultural Economics Staff Paper, No. 74-25 (September, 1974).

³¹Paul W. MacAvoy and Robert S. Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," Bell Journal of Economics and Management Science, Vol. 4, No. 2 (Autumn, 1973) pp. 454-498.

³²Ibid., pp. 489-493.

These data support a rapid growth in real natural gas prices.³³

A more sophisticated treatment of the substitution between natural gas and coal would take account not only of the usual cross elasticity between these substitutes, but also of the fact that in recent years there has been a shortage of gas. Thus, while a higher gas price makes gas less attractive, the anticipated increased supply of gas made available as a result of higher gas prices, but still at costs per BTU far below coal-fired electricity prices, will in fact reduce coal's market to some extent. The effect, over some range of gas price increases, is to reverse the normal positive impact of a rise in gas prices on the demand for coal.

MacAvoy and Pindyck project that at 61 cents per million BTU, gas production would be increased by 5.9 trillion cubic feet over production with strict cost of service regulation. So, at a price still far below the cost of electrical energy from coal, this additional incremental price rise of just 1.97% per year, over eight years, is projected to bring forth the energy equivalent of about 348 million tons of coal per year. How long this extra production could continue is a question not answered by MacAvoy and Pindyck. But while the extra production occurred, production of NGP coal could be substantially reduced. This is provided as a warning. In the following projections we have not attempted to adjust for this possibility.

³³In Part II, our price assumptions are also compared to a study of the Pacific Northwest by Butcher et al.

The results of our analysis are summarized in Table 15 in terms of projected growth rates for electric consumption for all permutations of the following four categories:

1. Two market areas: 21 states comprising the All FGD market for NGP coal, and 13 states comprising the All SCS market;
2. Three classes: Residential, Commercial and Industrial;
3. Three models: CEM/OLS, VEM/OLS, VEM/IV; and
4. Three growth rates for the real prices of electricity and natural gas: low, moderate and high.

As a generalization, for the low price increase CEM/OLS and VEM/OLS models project declining future growth rates in electric consumption of 5% 1974-1980, 3% 1980-1990 and 2% thereafter. The VEM/IV model projects approximately half this growth rate. The effect of even higher prices is an actual decline in future years.

In comparing the models, it should be noted that the estimated residual variance in Chapman's pooled cross-sectional and time series fit (see Table 15) is the largest for VEM/IV. An analysis of our state-specific time series fit for 1967-1973 shows: (1) The Residential sector gives excellent fit for all models. The degree of similarity among the models in this sector is striking. (2) In the Commercial sector, CEM/OLS and VEM/OLS give good fits. The VEM/IV model in almost all states gives a large overestimate of demand in 1973 (8-40%: especially large relative to errors in other years). (3) The Industrial sector, at best, gives a fair fit for CEM/OLS and VEM/OLS. The VEM/IV model gives poor fit, again with a large overestimate in 1972. One might conclude that an additional variable such as an index to regional industrial activity is needed. (4) Models

TABLE 15
ELECTRIC CONSUMPTION GROWTH RATES SUMMARY
Price-Sensitive Model

Price Increase Assumption (Electric, gas)	Model	Percentage Annual Rate of Growth		
		1974-79	1979-89	1989-99
A. <u>All FGD Market</u>				
1. (FPC, 3%)	CEM/OLS	5.66	3.27	1.99
	VEM/OLS	5.17	2.90	1.71
	VEM/IV	2.21	1.29	0.99
2. (3%, 5%)	CEM/OLS	4.33	0.77	-1.06
	VEM/OLS	3.94	0.49	-1.41
	VEM/IV	-0.49	-1.84	-2.42
3. (5%, 7%)	CEM/OLS	3.20	-1.29	-3.47
	VEM/OLS	2.88	-1.68	-4.22
	VEM/IV	-2.78	-4.63	-5.48
B. <u>All SCS Market</u>				
1. (FPC, 3%)	CEM/OLS	6.13	3.43	2.03
	VEM/OLS	5.56	3.12	1.86
	VEM/IV	2.47	1.39	1.06
2. (3%, 5%)	CEM/OLS	4.81	0.96	-0.99
	VEM/OLS	4.49	0.92	-1.09
	VEM/IV	0.06	-1.50	-2.18
3. (5%, 7%)	CEM/OLS	3.68	-1.11	-3.41
	VEM/OLS	3.53	-1.14	-3.91
	VEM/IV	-2.03	-4.20	-5.28

in general appear to have difficulty in reproducing a decline in demand over this time period. This is especially evident in the Montana Industrial sector. (5) Except that noted in (2) and (3), no time bias was observed (i.e. no consistent overestimate of demand in early years, or underestimate of demand in late years).

The analysis of the time series fit is summarized in Table 16, demonstrating that the CEM/OLS model is slightly better. The growth rates estimated by this model were used to project future generation in each of the market areas for all four price assumptions. The growth rate estimates are shown in Table 17. The actual projected levels of generation in kilowatt hours are found in Table A, Appendix II. In Figure 5, our "constant annual growth in electrical generation" approach (at 1%, 3% and 5%) and our "price-sensitive" projections (at constant, FPC and 3%, 3% and 5%, and 5% and 7% real annual price increase for electricity and gas, respectively) are plotted. As can be seen, the path for constant prices is close to the 5% growth projection, the low-price increase is close to the 3% growth projection, and the intermediate-price increase results in approximately 1% growth.

TABLE 16
SUMMARY ERROR ANALYSIS
Percentage of States with "Good" Time Series Fit*
1966 - 1973

	CEM/OLS	VEM/OLS	VEM/IV
Residential	71%	71%	85%
Commercial	80%	80%	9%
Industrial	42%	38%	9%
Average	64%	63%	34%

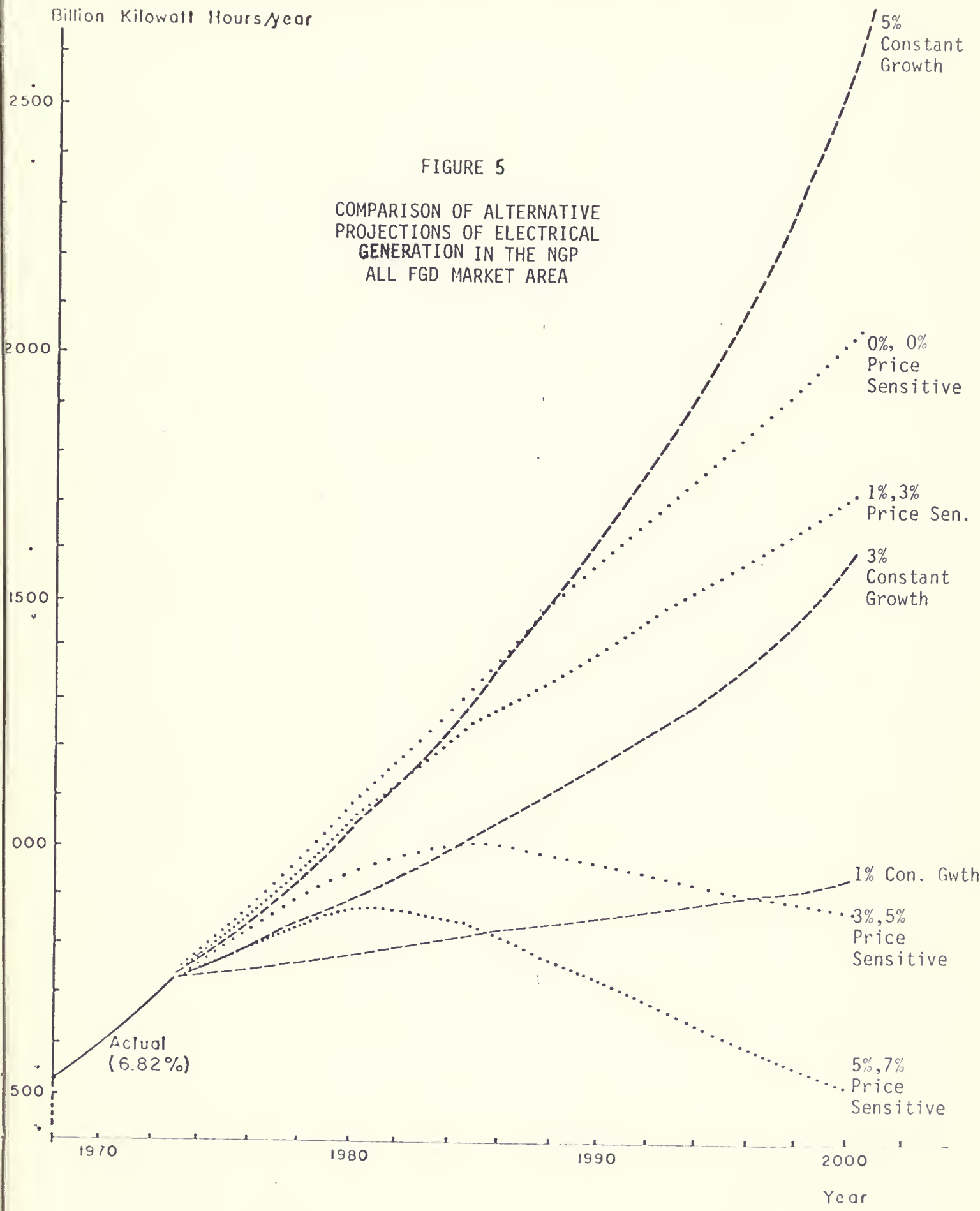
*Model time series estimate for 21 states, with "good" fits being those having (1) without-replacement estimates with maximum error (differing from actual by) less than or equal to 5% in any given year, and average error less than or equal to 1%; and (2) with-replacement estimates (the previous year estimate rather than the actual is used for the lagged demand variable) with maximum error in any given year less than 10% and average error less than 2%.

TABLE 17
ELECTRIC CONSUMPTION GROWTH RATES SUMMARY
CEM/OLS Model

Annual Percent Price Change (Electric, Gas)	<u>1974-1980</u>	<u>1980-1985</u>	<u>1985-2000</u>
A. <u>All FGD Market</u>			
0%, 0%	5.86	4.20	2.98
FPC, 3%	5.45	3.53	2.14
3%, 5%	4.00	1.14	-0.84
5%, 7%	2.79	-0.83	-3.26
B. <u>All SCS Market</u>			
0%, 0%	6.31	4.42	3.08
FPC, 3%	5.88	3.72	2.20
3%, 5%	4.45	1.36	-0.75
5%, 7%	3.23	-0.61	-3.18

FIGURE 5

COMPARISON OF ALTERNATIVE
PROJECTIONS OF ELECTRICAL
GENERATION IN THE NGP
ALL FGD MARKET AREA



Allocating the Electric Energy Demand between Fuels

The next step in relating electric energy demand to the consumption of NGP coal is to allocate the projected demand between competing fuels. This is probably the most uncertain step because the fuels mix is not simply a cost minimizing choice but is the target of state and U.S. federal and foreign government policies. The rate of development (and cost, reliability, safety, and public acceptability) of nuclear power, the availability of oil (and natural gas) as boiler fuels, the relative cost of residual oil, the enforcement of ambient air pollution standards (forcing the use of oil and natural gas as boiler fuels), etc., are difficult things to predict.

For this step of the analysis we took two different approaches. The first approach was to assume that the share of total generation that is coal-fired would remain constant in the future. The 39.0% share for the All FGD market and the 13.8% share for the All SCS market are based on the current actual share of electrical generation fired by coal in the respective markets. This estimate of coal-fired generation is given in Appendix I, Table B for the constant electrical growth assumption and in Appendix II, Table B for the price-sensitive assumption. Table F in the respective appendices gives the coal production in millions of tons per year associated with the estimates of coal-fired generation.

Our second approach to estimating coal's share of total generation was to estimate separately future nuclear, hydroelectric, gas- and oil-based generation and allocate coal as the residual. Tables C, D, E, F, and H in Appendices I and II summarize the estimates for the residual share approach. It was assumed that gas generation would remain constant

at 1973 levels, and that oil-fired generation would be zero (currently only 3.8% and 1.5% of the All FGD and All SCS markets, respectively).

Nuclear fueled electric power generating capacity in the Northern Great Plains coal market area was projected for 1980 and 1985 based on published construction schedules for announced plants and a review of the current status of the nuclear power industry in general.³⁴ Year 2000 nuclear generating capacity projections were based on varying assumptions about the growth in electric energy consumption and the assumption that beyond 1985 50% and 40% of all new generation in the All FGD 21-state and All SCS 13-state market areas respectively would be nuclear fueled. The projections of nuclear generating capacity made in this study are generally lower than previously published reports. The major hypothesis underlying the projections made here is simply that the growth in electric energy consumption in the United States will be lower than the recent historic trend. Other assumptions are that the current slippage in nuclear power plant construction from planned construction schedules will not be rapidly reversed and that there will be no dramatic rapid improvement in the average nuclear power plant capacity factor.

Projections of hydroelectric generating capacity in the NGP coal market area for 1980 and 1985 were also based on published construction schedules. The projection for the year 2000 is based on a review of the hydroelectric power resources (potential dam sites) both within the Northern Great Plains coal market area and in the entire United States along with an assessment of various existing year 2000 projections. The year 2000 projections presented here are based on the assumption that there will be

³⁴The nuclear and hydroelectric estimates are discussed more fully in John McBride, Working Papers #6 and #7, and in Arnold Silverman, Working Paper #5.

very little hydroelectric power development in Alaska, and that the social and economic benefits of the remaining free flowing rivers in the continental United States will begin to outweigh the benefits of hydroelectric power generation. Between 1985 and 2000, only 10,000 MW of additional hydroelectric generating capacity was projected to be developed. Sixty percent of this capacity was projected to be in the All FGD NGP coal market area and 55% in the All SCS market area.³⁵

These two approaches to projecting the fuel mix expected in electrical generation in the future differ primarily in the assumptions they make about the expansion of nuclear generating facilities. Implicit in the assumption that coal retains its 1973 share of electrical generation is a projection of nuclear generation. Table 18 compares this implicit nuclear projection with our direct one for the 21-state All FGD market.

If coal-fired generation is to hold to its 1973 share of electric generation while gas-fired generating capacity is held constant, oil-fired generation goes to zero, and hydro increases only moderately, nuclear generating capacity would have to increase somewhat faster than the growth in consumption of electricity. Given the lead times involved, we already know what the maximum nuclear generation could be in 1980 (and probably in 1985). This information for 1980 indicates that nuclear generation will expand as fast or faster than electric consumption only if there is very low growth in electric consumption. This is the reason that the "indirect" nuclear figures based on the constant share-to-coal assumption are in the same range as our direct estimates of nuclear generation in

³⁵John McBride, Working Paper #6.

TABLE 18
NUCLEAR ELECTRIC GENERATION PROJECTIONS

All FGD Market

Growth Assumption	(Billions of kilowatt hours/year)							
	Coal Retains 1973 Share of Electrical Generation ¹				Direct Estimate ²			
	1973	1980	1985	2000	1973	1980	1985	2000
Constant growth in electric consumption (% per year)								
1%	37.1	65.1	85.4	147.1	37.1	98.0	308.0	378.6
3%	37.1	135.0	217.8	551.4	37.1	98.0	308.0	596.7
5%	37.1	213.5	381.7	1221.0	37.1	98.0	308.0	1010.2
Price-Sensitive projections (% change in electric and NG prices per year)								
0%, 0%	37.1	250.1	396.8	826.6	37.1	98.0	308.0	675.6
FPC, 3%	37.1	232.4	350.2	616.9	37.1	98.0	308.0	542.0
3%, 5%	37.1	173.1	203.1	111.2	37.1	98.0	308.0	308.0
5%, 7%	37.1	127.3	101.5	-117.0	37.1	98.0	308.0	308.0

¹1973 actual data. 1980, 1985 and 2000 calculated as [Table A - Table B - Table C - 236.5 KWH/yr]. Tables A, B and C in Appendix I and II. See footnote 6, p. 136.

²Table D in Appendix I and II.

1980 only for low rates of growth of electric consumption (1%-3% per year) or high rates of increase in electricity prices (5% per year). Any faster rates of growth in electric consumption would require far more nuclear construction by 1980 than is planned if coal is to maintain its 1973 share. This suggests that the 1980 coal-fired figures derived from the constant share-to-coal assumption may be too low. For 1985, the planned nuclear construction schedule would allow coal to maintain its share if moderate rates of expansion of electricity consumption take place (3%-5% per year) or if moderate electric price increases take place (1%-2% per year). The two different nuclear projections for the year 2000 are quite similar for moderate and high rates of growth (3% and 5% per year) in electric consumption. Since the direct nuclear estimates for 1985 assume such growth, it is not surprising that these direct estimates are much larger than the indirect nuclear estimates for low rates of growth.

Allocating the Demand for Coal Among Alternative Sources

The final element in the projection is to estimate the share of coal demand in the NGP market region that will be met by NGP coal. Again, the implications of two alternative assumptions were examined: (1) that NGP supplies a share equal to its contract-based share in 1980, or (2) that NGP continues to supply contracts existing in 1973 plus all increases in demand for coal (all new coal-fired generation) after 1973.

The basis of both these approaches, and our specific projection for 1980, is our index of coal contracts for the Northern Great Plains.³⁶

³⁶William Tomlinson, Working Paper #4.

The contract data have been gathered from a wide variety of sources, including directories assembled by the Wyoming Geological Survey, the Montana Energy Advisory Council, news releases and articles, environmental impact statements and assessments, and certified statements entered into official administrative proceedings. These contract data represent the best information publicly available regarding contracts for NGP coal. There is no required public disclosure of contracts or contract stipulations.

It must be recognized that current contract data have many shortcomings since new contract agreements are pending and renegotiation of existing contracts can occur. In addition, contract totals are subject to error as a result of duplication in the literature because of company subsidiary listing being difficult to detect and reconcile, and nonreporting. The contract values listed are, therefore, low as a rule.

The contract data must be continually updated for validity. It is expected that additional contract data for the Northern Great Plains will become available in the next few months, giving us an opportunity to further validate the data used in this study and to fill in existing gaps. Based on the firm minimum contract estimate, our 1980 coal production for electric generation projection is 135.7 million tons. This figure, which is a conservative estimate, is the basis of the alternative coal production scenarios outlined below. The "contract-based share" in the coal source assumption mentioned previously is calculated by taking the ratio of the actual coal contracts in 1980 (135.7 million tons) to the projected total coal demand for electrical generation at 5% growth (202.2 million tons for the constant share case [see Table G, Appendix I] and 260.8 million

tons for the residual share case [see Table H, Appendix I]). In Summary Table 1, page 5, the contract shares at all growth levels are displayed; however, only the .67 and .52 shares at 5% were used in allocating 1985 and 2000 demand for coal. We reason that coal contracts and plans for future nuclear and hydroelectric generation construction assume at least a 5% growth rate through 1980. While this may or may not be a case of bad judgment on the part of utility managers, coal contracts and power plant construction contracts have committed the utilities to at least this 5% growth in generating capacity through 1980. We use these contracts and commitment in 1980 as our base. This amounts to assuming that the share of electric generation fired by coal or the share of that coal being purchased in the NGP will not vary with the level of electric energy demand but will hold to the mix indicated at "preferred" by the industry in their 1980 contracts and construction plans.

Similarly, in calculating the contract share for the price-sensitive projection (Summary Table 2, page 6), we have used the share corresponding to the Federal Power Commission projection of electricity price increase and a 3% annual gas price increase. It is our judgment that this set of price increases most closely approximates the increase assumed by industry planners, and embodied in their construction and coal contract plans.

It should be clearly noted that the data used in our projections are firm contract estimates, not "mine production estimates". Mine production estimates are the quantity of coal a mine could produce at a given time provided contracts to sell that quantity existed. Mine production estimates are generally higher than firm contracts and are often reported by the news media instead of contract estimates. Table 19 compares our

contract estimates with mine production estimates for the three Northern Great Plains states. For 1980, the mine production estimate (minimum) is 35% higher than the contract estimate. Table 20 shows existing NGP coal contracts by state of destination.

TABLE 19
NORTHERN GREAT PLAINS COAL CONTRACT DATA SUMMARY
Production Estimate 1980 by State of Origin

State of Origin	Mine Production Estimate	Contract Estimate
Montana	56.92 million tons	37.52 million tons
Wyoming	101.30 million tons (min.) 143.50 million tons (max.)	84.26 million tons (min.) 94.21 million tons (max.)
North Dakota	24.67 million tons (min.) 27.47 million tons (max.)	13.92 million tons
Total	182.89 million tons (min.) 227.89 million tons (max.)	135.70 million tons (min.) 145.65 million tons (max.)

SOURCE: William Tomlinson, Working Paper #4.

TABLE 20
NORTHERN GREAT PLAINS COAL CONTRACT DATA SUMMARY
Utilization Estimate 1980 by State of Destination

State of Destination	Contracted Supply
Arkansas	6.75 million tons
Colorado	2 - 2.20 million tons
Idaho	4.25 - 4.75 million tons
Illinois	5.5 million tons
Indiana	15 - 18 million tons
Iowa	3.05 - 3.55 million tons
Kansas	5 million tons
Louisiana	4.25 million tons
Michigan	7.2 million tons
Minnesota	4.45 million tons
Missouri	2.35 million tons
Montana	14.62 million tons
Nebraska	3.6 million tons
North Dakota	13.1 million tons
Oklahoma	6.6 million tons
Oregon	1.45 million tons
South Dakota	.57 million tons
Texas	10.3 - 12.05 million tons
Wisconsin	6.15 million tons
Wyoming	19.51 - 23.51 million tons

SOURCE: William Tomlinson, Working Paper #4.

Alternative Scenarios

Summarizing the assumptions for the constant growth in electric energy generation approach, the projected level of NGP coal development will depend on the geographic extent of the market (All FGD vs. All SCS), the growth of electric energy demand (1%, 3%, or 5%), the fuel mix (constant share to coal or residual to coal), and fuel source (all new coal demand or a constant 1980 contract share). This set provides 24 permutations for each projected year as suggested by Table 21.

TABLE 21

RELATIONSHIP OF ASSUMPTIONS TO PROJECTION

Market and Growth Assumptions		Table	Fuel Mix and Source Assumptions	
All FGD Market	1%)	I	Constant Coal Share)	NGP supplies
	3%)	J	Coal Share Residual)	1980 share
	5%)			
All SCS	1%)	K	Constant Coal Share)	NGP supplies
	3%)	L	Coal Share Residual)	all new
	5%)			

The calculations related to each of the methodological steps discussed above are given in Appendix I. The actual projections are found in Tables I, J, K and L, based on the four possible combinations of fuel mix and fuel source situations (for each of the two market and three growth assumptions). Since the coal source assumption that the NGP supplies all new coal-fired electric generation but none of the plants already in operation in 1973 which were using midwest coal gives 1980 results which are much less than half our firm contract estimate (see Tables K and L in Appendix I), this permutation does not appear to be

reasonable. Similarly, as a methodological step, we calculated the coal demand in the market area if NGP supplies all coal in its market area, rather than its 1980-based contract share. These numbers are given in Appendix I, Tables G and H.

Since our 1980 projection is based on firm contracts (for 135.7 million tons), the permutation corresponding to this contract-based share of the coal fuel supply continuing to be supplied by the NGP in future years appears most reasonable to use. In Table 22, Tables I and J, from Appendix I, corresponding to this permutation are reproduced.

Part A of Table 22 shows the projection for the fuel mix assumption that coal will continue to fuel its current share of total generation in the NGP market area. Our 1980 contract estimate is 88%, 77% and 67% of the total demand for coal in the market area at 1%, 3% and 5% growth, respectively. As discussed previously, we have used the share at 5% growth for the 1985 and 2000 projections.³⁷ Part B shows the projection for the residual share fuel mix assumption--based on coal being allocated a residual share of all generation after the shares for oil, gas, hydroelectric and nuclear-fueled generation are projected independently. In this case, our 1980 contract estimate is 99%, 69% and 52% of the respective growth level projections for total coal demand.

In choosing between alternative fuel mix assumptions, the residual fuel mix approach shows a decline for 1985 and 2000 at low levels of growth. This follows from the fact that actual planned nuclear and hydroelectric generating capacity is based on the assumption of a high level of annual electric growth--5% or more. Therefore, at low levels of growth the residual share to coal is unreasonably small and even negative (shown as zero) for the Partial FGD market estimate. This inconsistency

³⁷See page 54.

TABLE 22

COAL PRODUCTION IN THE NORTHERN GREAT PLAINS
BASED ON CONSTANT GROWTH IN ELECTRICAL GENERATION
AND THE 1980-BASED CONTRACT SHARE OF ALL COAL DEMAND

PART A: Coal Production based on the Assumption of a Constant Share to Coal vis-a-vis Other Fuels*

Growth in Electrical Production	1980 NGP Coal Share	(Millions of Tons)		
		1980	1985	2000
<u>All FGD Market Estimate*</u>				
1%	.88	135.7	108.5	126.0
3%	.77	135.7	137.3	213.8
5%	.67	135.7	172.9	359.5
<u>Partial FGD Estimate</u>				
1%	.88	135.7	34.4	51.8
3%	.77	135.7	63.1	139.8
5%	.67	135.7	98.8	285.4

PART B: Coal Production based on the Assumption that the Residual Share of the Fuel Mix within the NGP Market Area will be filled by Coal Fired Generation

Growth in Electrical Production	1980 NGP Coal Share	(Millions of Tons)		
		1980	1985	2000
<u>All FGD Market Estimate</u>				
1%	.99	135.7	25.4	36.7
3%	.69	135.7	82.8	154.0
5%	.52	135.7	153.7	334.7
<u>Partial FGD Estimate</u>				
1%	.99	135.7	0	0
3%	.69	135.7	19.9	91.2
5%	.52	135.7	90.8	271.8

*Our "most likely" assumptions and projections.

in growth assumptions suggests to us that the constant share to coal permutation is most reasonable for it does not force the mix of fuels to vary with the level of electric generation. It may be noted that the interfuel substitution aspect is probably the weakest part of our analysis. We were forced by constraints on time and funding to rely in this case on secondary sources rather than develop our own model.

Concerning the electrical demand growth assumption, the 1% level appears quite unlikely. The most reasonable level of growth probably is 3% to 5%.

For both market estimates, our 1980 figure is based on firm contracts at 135.7 million tons. However, the "Partial FGD" estimate for 1985 and 2000 is the projected demand if SCS are allowed on existing plants. As can be seen in Table L, this change in current policy would result in a drastic decline in coal production in 1985 and 2000. Demand by new plants in the entire All FGD market area would continue to be satisfied by NGP coal, but demand by existing plants would be economical only in the 13-state area. (In Appendix II, we have also included an even smaller All SCS market projection in many of the tables. This set corresponds to the case where the consumption by both existing and new plants is limited to the smaller 13-state area.) Given present policy, the All FGD market estimate appears most reasonable.

We would conclude that the permutation corresponding to our All FGD market, constant share to coal vis-a-vis other fuels, 1980-based contract share of this coal to the NGP, and 3% and 5% electrical growth is the most reasonable projection. These numbers are shown in Table 22.

For the price-sensitive case, a corresponding set of calculations are found in Appendix II. This projection is summarized in Table 23, based on our alternative levels of future electricity and gas prices: constant or 0% annual growth, approximately 1% electricity (based on region-specific FPC numbers) and 3% gas, 3% electricity and 5% gas, and, finally, 5% electricity and 7% gas. Again, the most reasonable projection corresponds here to the FPC, 3% price increase case and the 3%, 5% case and the same set of market, fuel mix, and fuel source assumptions as in Table 22.

In Table 22 for low (1%-3%) rates of growth in electric consumption, the demand for NGP coal either falls or remains almost constant between 1980-1985 indicating that the current contracts assume rapid expansion in electric consumption. The same can be seen in the price-sensitive projections of Table 23 for rapid rises in the prices of electricity and natural gas. There are important long run differences between the two tables, however. When consumption is made price-sensitive (as in Table 23) and prices are allowed to rise slowly but continuously, demand for NGP coal in the long run (by the year 2000) grows only very slowly or not at all. The slowly rising energy prices have a significant retarding effect on demand for coal. On the other hand, if constant growth in consumption is assumed (as in Table 22), then in the long run even with slow rates of growth in consumption (e.g. 3% per year), the demand for NGP coal does rise significantly.

The only difference between Tables 22 and 23 is in the electrical generation growth projection; the reader will recall the comparison of the results of our two methods shown in Figure 5, page 47.

TABLE 23

COAL PRODUCTION IN THE NORTHERN GREAT PLAINS
 BASED ON PRICE-SENSITIVE ESTIMATES OF GROWTH IN ELECTRICAL GENERATION
 AND THE 1980-BASED CONTRACT SHARE OF COAL DEMAND

Price Sensitive Coal Production based on the Assumption of a Constant Share to Coal vis-a-vis Other Fuels*

Annual Rate of Price Increase (Electric, Gas)	1980 NGP Coal Share	(Millions of Tons)		
		1980	1985	2000
<u>All FGD Market Estimate*</u>				
0%, 0%	.63	135.7	171.0	265.6
FPC, 3%*	.65	135.7	161.1	221.3
3%, 5%*	.72	135.7	130.1	114.7
5%, 7%	.78	135.7	108.6	66.5
<u>Partial FGD Estimate</u>				
0%, 0%	.63	135.7	99.0	193.6
FPC, 3%	.65	135.7	89.1	149.4
3%, 5%	.72	135.7	58.2	42.7
5%, 7%	.78	135.7	36.7	0

Price Sensitive Coal Production based on the Assumption that the Residual Share of the Fuel Mix within the NGP Market Area will be filled by Coal Fired Generation

Annual Rate of Price Increase (Electric, Gas)	1980 NGP Coal Share	1980	1985	2000
<u>All FGD Market Estimate</u>				
0%, 0%	.47	135.7	151.0	237.8
FPC, 3%	.49	135.7	132.0	185.5
3%, 5%	.60	135.7	72.0	37.5
5%, 7%	.72	135.7	30.5	0
<u>Partial FGD Estimate</u>				
0%, 0%	.47	135.7	91.7	178.5
FPC, 3%	.49	135.7	72.7	126.3
3%, 5%	.60	135.7	12.7	0
5%, 7%	.72	135.7	0	0

*Our "most likely" assumptions and projections.

The following tables provide a projection of the coal production by state. Total production as shown in the tables was allocated on the basis of each state's share of coal production contracts. Of the 135.7 million tons under contract for 1980, 37.52 million will be mined in Montana (27.6%), 13.92 million tons in North Dakota (10.3%), and 84.26 million tons will originate in Wyoming (62.1%).³⁸

We will conclude here by noting that our analysis is meant not only to project a likely level of coal development but, perhaps more importantly, to show the relationships among the critical variables and the sensitivity of the projection to changes in the variables. For example, while contract information certainly suggests that utilities are behaving as though a lime/limestone scrubber FGD system will be required (and, therefore, suggesting the All FGD market definition), in fact, if less stringent pollution standards become federal policy, the All SCS market estimate will become relevant.

³⁸William Tomlinson, Working Paper #4.

TABLE 24

ALLOCATION OF NGP COAL PRODUCTION BY STATE
 BASED ON THE ASSUMPTION OF CONSTANT ELECTRICAL GENERATION GROWTH
 AND THE 1980 CONTRACT SHARE OF COAL PRODUCTION

	Growth in Electrical Consumption	(Millions of Tons)		
		<u>1980</u>	<u>1985</u>	<u>2000</u>
<u>All FGD Market Estimate</u>				
Montana (27.6%)	1%	37.5	39.3	45.6
	3%	37.5	43.6	67.8
	5%	37.5	47.7	99.2
Wyoming (62.1%)	1%	84.3	88.5	102.7
	3%	84.3	98.0	152.6
	5%	84.3	107.4	223.2
North Dakota (10.3%)	1%	14.0	14.7	17.0
	3%	14.0	16.3	25.3
	5%	14.0	17.8	37.0
<u>Partial FGD Market Estimate</u>				
Montana (27.6%)	1%	37.5	12.4	18.8
	3%	37.5	20.4	44.3
	5%	37.5	27.3	78.8
Wyoming (62.1%)	1%	84.3	28.0	42.2
	3%	84.3	45.1	99.8
	5%	84.3	61.4	177.2
North Dakota (10.3%)	1%	14.0	4.7	7.0
	3%	14.0	7.5	16.5
	5%	14.0	10.1	29.4

TABLE 25

ALLOCATION OF NGP COAL PRODUCTION BY STATE
 BASED ON A PRICE-SENSITIVE ESTIMATE OF ELECTRICAL GENERATION GROWTH
 AND THE 1980 CONTRACT SHARE OF COAL PRODUCTION

	Annual Rate of Price Increase (Electric, Gas)	(Millions of Tons)		
		<u>1980</u>	<u>1985</u>	<u>2000</u>
<u>All FGD Market Estimate</u>				
Montana (27.6%)	0%, 0%	37.5	45.8	71.0
	FPC, 3%	37.5	44.5	61.0
	3%, 5%	37.5	39.8	35.0
	5%, 7%	37.5	36.0	22.0
Wyoming (62.1%)	0%, 0%	84.3	102.9	159.8
	FPC, 3%	84.3	100.0	137.4
	3%, 5%	84.3	89.5	78.9
	5%, 7%	84.3	80.9	49.6
North Dakota (10.3%)	0%, 0%	14.0	17.1	26.5
	FPC, 3%	14.0	16.6	22.8
	3%, 5%	14.0	14.8	13.1
	5%, 7%	14.0	13.4	8.2
<u>Partial FGD Market Estimate</u>				
Montana (27.6%)	0%, 0%	37.5	26.4	51.8
	FPC, 3%	37.5	24.5	41.2
	3%, 5%	37.5	17.8	13.0
	5%, 7%	37.5	12.1	0
Wyoming (62.1%)	0%, 0%	84.3	59.3	116.6
	FPC, 3%	84.3	55.3	92.8
	3%, 5%	84.3	40.0	29.4
	5%, 7%	84.3	27.3	0
North Dakota (10.3%)	0%, 0%	14.0	9.8	19.3
	FPC, 3%	14.0	9.2	15.4
	3%, 5%	14.0	6.6	4.9
	5%, 7%	14.0	4.5	0

B. Forecasting Coal Gasification Activity in the Northern Great Plains

Introduction

Interest in the gasification of coal has grown substantially in the last few years as natural gas use in the United States has increased while proved reserves have fallen.¹ Since the states of Montana, Wyoming and North Dakota have large supplies of coal, accessible by stripping at relatively low cost, much of the nation's interest is focused in this region. Water, another crucial input to coal gasification, also is available, though the social cost of using water in this fashion is being vigorously debated. The extent of coal gasification over the next several years will do much to determine the total impact--feared by some, desired by others--which coal development will have on the region.

The history of coal gasification technology goes back to 1670.² Probably the most thoroughly proven technology is that used in Lurgi units, of which fifty have been built. To make pipeline quality gas, having about 1,000 BTU per standard cubic foot (scf), however, requires a further process, methanation, which is not yet in commercial use. New technologies are also being explored, but the first plants are expected to use the Lurgi process with methanation.

The decision as to how much coal, water, capital, and other

¹The total reserves-to-annual production ratio fell from 18.9 in 1963 to 9.7 in 1973. FPC, "Future Domestic Natural Gas Supplies," National Gas Survey (preliminary draft) Vol. 1, Ch. 9 (Washington, DC: Federal Power Commission, 1975).

²For a brief history and description of coal gasification and technology, see FEA, "Synthetic Fuels from Coal," Project Independence Report (Washington, DC: Government Printing Office, November, 1974).

resources to devote to coal gasification is, of course, an economic decision. To predict the time path of gasification development, one must consider both the cost and the value of the product. It is also true that simple managerial economics are insufficient in this case to yield good predictions. Governmental regulation of gas production, pricing and distribution, as well as plant siting, water use, and other aspects of plant location, makes this a question of political economy. The forecaster's judgments must be tempered by recognition of non-market determinants of coal gasification's development. Still, the purely economic factors seem likely to have a powerful influence. If expected costs are very much higher than expected product value, it seems unlikely that extensive development will occur. Likewise, costs which are quite low, relatively, would be expected to militate persistently for development of facilities. Even though government has the power to grant enormous subsidies, or to tax what may be low-cost alternatives out of existence, we believe that when the costs clearly are too great, a program is unlikely to be undertaken--and that the reverse holds true, also.

Coal Gasification Costs

Since commercial-scale plants to make substitute natural gas (SNG) from coal have never been built in the United States, there is substantial uncertainty concerning costs. However, the Synthetic Fuels from Coal Task Force Report of the Project Independence Blueprint provides cost estimates for high-BTU gas plant construction. Both capital requirements and projected fuel prices are uniquely usable in that

breakdowns of component costs are given along with the projections.

Those projections are the basis for the following cost estimates.

In late 1973 dollars, total capital requirements for a 23 billion BTU/day (approximately 250 million cubic feet/day) plant with methanation were estimated at \$427.097 million.³ Assuming coal costs of \$4.00 a ton, and internal utility financing at 9%, a unit price of \$1.44/MMBTU⁴ was derived. When these assumptions are updated, with capital investment at \$800 million,⁵ coal at \$4.50 per ton,⁶ and using updated operating costs figures, the cost rises to \$2.18 per MMBTU, in late 1974 dollars.⁷

Estimates assuming other than internal utility financing project a considerably higher price of gas from the same plant. Given the uncertainty involved, traditional utility-style financing appears to be inappropriate. Project Independence arrives at a price of \$2.55/MMBTU⁸ when the plant is investor-financed with a 15% discounted cash flow (DCF). This figure is projected under cost assumptions similar to the \$1.44 figure which assumes utility financing. If the 15% DCF numbers

³FEA, "Synthetic Fuels from Coal," Project Independence Report, p. 35.

⁴Ibid., p. 36.

⁵From a conversation with Dr. Seay, American Institute of Gas Technology, concerning the proposed Four Corners area and North Dakota coal gasification projects.

⁶An aggregate figure of 14 million tons of bituminous coal shipped from Montana mines in 1974, as reported by Mr. King, Montana Bureau of Mines, in a telephone conversation, July 24, 1975.

⁷A more recent and concrete estimate of unit price comes from the American Natural Gas Company, proposing a Lurgi plant in North Dakota. Their current estimate is \$2.58/Mcf (roughly comparable to and slightly higher than a MMBTU price). This price includes limited transportation to the distribution network and is given in late 1974 dollars.

⁸FEA, "Synthetic Fuels from Coal," Project Independence Report, p. 36.

have changed by the same percentage as the utility finance figures, the appropriate cost becomes \$3.86 per MMBTU.

In any cost consideration of synthetic coal gas, it should be kept in mind that pipeline-quality gas production is not a commercially proven technology. Further research and development needs to be funded and carried out before the first plant operates. In general, significant amounts of development are required in the areas of high-pressure feed systems,⁹ pollutant analysis and control,¹⁰ application of technology to various coal types,¹¹ the methanation process,¹² and scaling up processes from experimental to commercial size.¹³

In addition to these more scientific areas of research and development, work is needed on engineering problems of actual plant construction. These include unsolved problems of field erection and fabrication of pressure vessels.¹⁴ The large size of such vessels precludes shop fabrication and necessitates field adaptations of precision techniques previously untried.

Value of SNG

The value of gas made from coal is determined by the value of (demand for) energy, and the price, availability, and suitability in use

⁹FEA, "Synthetic Fuels from Coal," Project Independence Report, pp. 44-45

¹⁰Ibid., pp. 23, 83-90.

¹¹Ibid., p. 24

¹²U.S. Department of the Interior, Office of Coal Research, "Pipeline Quality Gas," Evaluation of Coal-Gasification Technology, Part I (Washington, DC: Government Printing Office, 1974); and Federal Power Commission, Final Report of the Supply-Technical Advisory Task Force: Synthetic Gas-Coal (Washington, DC: Federal Power Commission, 1973).

¹³FEA, "Synthetic Fuels from Coal," Project Independence Report, p. 24.

¹⁴Ibid., pp. 63, 68-70 and 118.

of energy from other sources. Greater demand for energy increases the value of SNG, while lower price, greater availability and greater suitability in use of other energy sources lower the value of SNG.

Energy use in the U.S. has been rising for many years. In 1974, however, energy consumption fell by 2.7%.¹⁵ This is consistent with the fact that in real terms (corrected for inflation) energy prices fell steadily for decades until 1973, when they began to rise sharply.¹⁶ It is estimated that, other factors considered, energy use will decline 1.5% to 5% if energy prices rise 10 percent. Of course, the economic recession of the time, social pressures, and population growth probably had significant impacts also. To estimate the demand for SNG as a function of its price, one must consider these factors as well as the prices of substitutes.

The most important competitor for SNG is, presumably, natural gas. Both the price of natural gas and its supply are crucial determinants of the need for gasified coal. Indeed, recent shortfalls of natural gas supply are the reasons for serious consideration of the technology. An understanding of the nature of these shortages is crucial to a reasoned analysis of the supply options available.

While natural gas has a high value, especially to home consumers,

¹⁵Council of Economic Advisors, Economic Report of the President (Washington, DC: Government Printing Office, February, 1973), p. 80.

¹⁶E.J. Mitchell, "The Energy Dilemma: Which Way Out?" Reprint No. 32 (Washington, DC: American Enterprise Institute for Public Policy Research, June, 1975).

¹⁷N. Edmonson, "Real Price and Consumption of Mineral Energy in the U.S., 1900-1968, Journal of Industrial Economics [University of Manchester] (forthcoming) p. 3; and Edward A. Hudson and Dale W. Jorgenson, "Energy in the United States: Projections and Policy," manuscript for the Energy Policy Project of the Ford Foundation (Washington, DC: Ford Foundation Energy Policy Project, 1974).

due to its clean and continuously deliverable nature, its price is controlled somewhat below a market-clearing level by the Federal Power Commission. Until recently (1970), new wellhead prices were below \$0.20/Mcf. With prices controlled at this level, the value of gas was understated, the demand for it was overstimulated, and incentives to explore and produce were retarded. Now, the FEA has projected forced curtailments of gas contracts of 2.9 trillion cubic feet (Tcf) for the twelve months starting April 1975, as reported in "Weekly Energy Report" for September 1, 1975. Production in 1974 was approximately 22 Tcf. Some states will see cutbacks of up to 45% of demand at the regulated price. Dislocation from shortages of this magnitude can and will be serious but will the considered costs and value of SNG lead to its use in plugging the supply-demand gap?

A critical question is whether gas could be made available at prices lower than SNG costs, in quantities great enough to eliminate SNG demands. To answer this question quantitatively requires the consideration of many forces, interacting in dynamic and complex ways. Such a study is beyond the scope of this project but, fortunately, such a study has recently been done at the M.I.T. Energy Laboratory, primarily by MacAvoy and Pindyck.¹⁸ Their econometric modelling and simulation of phased deregulation of natural gas indicates that at an average wholesale price of \$0.61/Mcf (in 1974 dollars) by 1980 the market for pipeline natural gas would clear, leaving no room for SNG. Their

¹⁸P. MacAvoy and R. Pindyck, Price Controls and the Natural Gas Shortage (Washington, DC: American Enterprise Institute for Public Policy Research, May, 1975).

calculated supply responses are questioned by some experts.¹⁹ Yet even if their projected equilibrium price were to be quadrupled, SNG produced from NGP coal still would have no U.S. market, due to natural gas competition alone. In the NGP states' own markets--partially dependent on Canadian gas imports of questionable future--full reliance on natural gas may require new pipeline construction in addition to in-region gas field development.

Another important competitor, at least for industrial sales of SNG from coal, could be coal itself. At a price of \$4.50 per ton, coal costs about 26.4¢ per million BTU²⁰ or the energy equivalent of about \$0.265 per Mcf of SNG. Much of coal's "substitutability" for gas is dependent on the availability of pollution control technology,²¹ and of course transport costs and burning efficiencies will differ. Still, coal could be a cheaper supplement to natural gas in some large-scale uses, when compared with SNG.

¹⁹As a basis for their supply response projections, MacAvoy and Pindyck used physical gas reserve estimates from the Potential Gas Committee, an industry organization unique in its access to proprietary information. For purposes of comparison, the PGC estimate of potential supply is listed below, along with comparable estimates from other sources: (These figures do not include proved reserves.)

COMRATE (Nat. Acad. of Sciences, 1975) - 530 Tcf;

Mr. King Hubbert (1974) - 540 Tcf;

McKelvey (U.S. Geological Survey, 1975) - 320-655 Tcf; and

Potential Gas Committee (as of 12/31/72, ex Alaska) - 780 Tcf.

²⁰The \$4.50 per ton figure is the same one used in calculating SNG costs above. These calculations assume 17 million BTUs per ton of coal. Note that as coal at the mine rises in price, SNG energy rises in cost faster than does energy from coal burned directly, since more coal is required to produce a unit of SNG energy.

²¹For recent summary on the crucial problem of flue gas desulfurization, J. Jonakin, "Solving the SO₂ Problem - Where We Stand with Applications and Costs," Coal Age (May, 1975).

While large-scale and industrial gas users may be expected to react promptly to higher gas costs, the residential and commercial space heating sector is likely to exhibit a more inelastic, slower response. Still, competitive alternatives exist. Electricity may be a relatively low-cost option considering modern heat pump technology. Hammond and Zimmerman²² of the M.I.T. Energy Laboratory project heating costs significantly lower from electricity-powered heat pumps than from SNG, using assumptions biased in favor of SNG technology and gas burning efficiency.²³

In some cases, fuel oil, liquefied petroleum gas (LPG) and low-BTU gas produced for nearby boilers, may also compete with SNG, but generalizations are difficult, as estimates on price and availability vary. The outlook regarding solar, wind, tide, and other more exotic energy sources also varies with the observer. However, many believe that by the year 2000 substantial production from one or more of these sources is likely.

In this study, we did not attempt to estimate the potential additional coal production in the NGP that might be needed to replace natural gas in industrial boilers and to replace natural gas in residential heating via coal-fired electric generation. Instead we attempted to estimate an upper limit on what this coal substitution for natural gas might be. Our analysis of natural gas reserves led us to conclude that in this century natural gas could be made available to satisfy the residential, commercial, and industrial demand that would exist at significantly higher natural gas prices.

²²Ogden Hammond and Martin B. Zimmerman, "The Economics of Coal-Based Synthetic Gas," Technology Review, Vol. 77, No. 8 (July/August, 1975), pp. 15-22.

²³Included in the assumptions were SNG prices (delivered) at \$3.65/MMBTU and electricity at 4.3¢/KWH. Adoption of heat pump technology may be more likely, or more important for potential SNG export markets than for NGP states' own demands, due to decreased heat pump efficiency at very low temperatures.

Thus, our "most likely" projection is for neither coal gasification nor significant substitution of coal for natural gas. However, a combination of federal regulatory policies and natural gas industry long run profit-oriented responses might lead to significant shortages of natural gas in the future. In that case, both gasification and the substitution of coal for natural gas might become realities. In this "high demand" (for NGP coal) case, we project three gasification plants (22.5 million tons of coal per year) plus an additional 33-63 million tons of coal which are produced in the NGP to substitute directly for restricted natural gas supplies.

As mentioned earlier, this fuel substitution analysis is the weakest part of our study. It lay outside this study to estimate the amount of "new" natural gas that would be stimulated by higher prices (but prices still below those required to cover the capital and operating costs of converting industrial boilers to coal. Likewise, we did not attempt to quantify the "conservation" that would take place because of higher fuel costs before any dramatic switch between fuels would take place. Although we did not quantitatively deal with a natural gas "shortage" situation, our price-sensitive model did take into account the impact of natural gas prices rising faster than electricity prices and the substitution of coal for natural gas this would encourage. This, we felt, was the "most likely" long run situation.

Forecasting Coal Gasification

Since predicting the time path of coal gasification is a problem in political economy, some assumptions must be made regarding the goals or preferences to be exhibited by decisionmakers in and out of government. The fundamental assumptions made here are that energy users will try to minimize the cost of energy consumed, as well as reacting to higher energy prices by decreasing their energy use (conservation). Available

data support these notions. Also, it will be assumed--at least in the "most likely" projections--that regulatory agencies move in the direction tending to encourage cost minimization in energy supply.

Given the cost estimates for SNG from coal, and the apparent availability of natural gas at costs much less than SNG cost estimates, the market for SNG seems not to exist. Even if the M.I.T. market-clearing price of \$0.61 per MMBTU is low by a factor of 4, natural gas should be cheaper. The long-run availability of gas is very much in question, however, as geologic experts disagree on potential production from reserves (see footnote 19). Virtually all estimates, though, appear to suggest that we can continue to have domestic gas available beyond the year 2000, provided that annual use does not increase dramatically--and much higher prices should strongly encourage conservation rather than greater use. Also, if natural gas is available in substantially smaller quantities than present, the cost advantage of utilizing energy directly from coal and its applicability in industrial markets may free existing industrial gas supplies to be channeled to other, higher valued uses.

All factors considered, we forecast that there will be no commercial production of SNG in the Northern Great Plains in 1980 or 1985. Since commitments must be made in the next two to four years for production by 1985, we are reasonably confident in this forecast. To predict output of SNG (or any other commodity) in the year 2000 is exceedingly difficult. Society's ignorance of fossil fuel reserves--which is rational in light of the cost involved to learn much more--together with the uncertainty of foreign fuel-source prices and availabilities, make forecasting natural gas production for the year 2000 almost a guessing game. We arbitrarily

will assume that cost relationships, technology, and regulatory factors will remain close enough to the currently foreseeable situation that SNG production also will remain non-feasible economically at that point.

Obviously, if we change our assumptions to be more adverse toward SNG production, our "low" forecasted amounts will remain at zero.

If we change our assumptions to be more favorable toward SNG production, the predictions could change. For example, if technological advances substantially reduce SNG costs, and if natural gas were far less available in the future even at much higher prices (or at low controlled prices), while engineers were unable to design environmentally acceptable ways to switch many users from gas to coal, then SNG might become feasible.²⁴

Another possibility is that with continued strong regulation holding down the domestic price and availability of natural gas and oil, the pressures, due to shortages, on Congress might be such that instead of allowing higher natural gas and oil prices, enormous subsidies might be granted in an effort to supplement supply and hence SNG production would be encouraged.²⁵ The apparent rationale for such a move would be to keep gas prices low to the consumer. But with presently projected SNG costs, the social cost of such energy would certainly be higher than under alternative regulatory and technologic options.

²⁴ Another factor of some importance in the Northern Great Plains is the potential elimination of Canadian supplies, although such a move would seem to be very costly for Canada, given the price they get for exports as compared to internal Canadian prices. In the national picture, these amounts are small.

²⁵ For a discussion of this possibility, see R. Stroup and V. House, "The Political Economy of Coal Gasification: Some Determinants of Demand for Western Coal," presented at the Western Economics Association meetings, San Diego, June 26, 1975 (Bozeman, MT: Montana State University, Department of Agricultural Economics and Economics, Staff Paper #75-17).

The high cost of synthetic gas could be masked to some extent by averaging the cost in with regulated, low-priced natural gas ("rolling in"), thus making the gas marketable and the venture profitable for the producer. But a rolled-in price is artificial in that it doesn't represent the true cost to society of producing the gas. When the social cost (eventual consumer cost) is realized, SNG emerges as a high-cost solution. Because of our assumption that regulators tend toward economic rationality, we do not really expect that chain of events to occur, but we recognize their possibility. So, our "high" forecast--at this point rather arbitrary in nature--is that while no plants will be in production by 1980, one in each state will be operating by 1985, with no change by the year 2000.

TABLE 26

SUMMARY OF GASIFICATION PROJECTIONS

SNG Plants in Montana, Wyoming, and North Dakota

	<u>1980</u>	<u>1985</u>	<u>2000</u>
Most likely	0	0	0
Low	0	0	0
High	0	3	3

Note: All plants rated at 250 MM scf/day.

TABLE 27

COAL GASIFICATION IN THE NORTHERN GREAT PLAINS

Coal Gasification Plants in the Northern Great Plains

	<u>1980</u>	<u>1985</u>	<u>2000</u>
Most likely	0	0	0
Low	0	0	0
High	0	3	3

Note: All plants rated at 250 MM Scf/day. One plant each will be located in Montana, Wyoming and North Dakota in the high estimates.

Coal Requirements for Gasification Plants in the Northern Great Plains

	(Million Tons per Year)		
	<u>1980</u>	<u>1985</u>	<u>2000</u>
Most likely	0	0	0
Low	0	0	0
High	0	22.5	22.5

Note: Each plant requires 7,500,000 tons per plant-year of operation.

Coal Exports from NGP to Make Up NG Shortfalls

	(Million Tons per Year)		
	<u>1980</u>	<u>1985</u>	<u>2000</u>
Most likely	0	0	0
Low	0	0	0
High	0	17-34	33-67

Note: This assumes the shortages are all assigned to industrial users. Increases in industrial demand for NG in the 21-state market are filled by export of NGP coal and midwestern coal. The share to NGP coal is assumed to be the same as the share of coal-fired generation.



C. Liquefaction, Fertilizer Production, and Other Uses
for Northern Great Plains Coal

There are several additional new technological processes which use coal as a feedstock. These processes include the liquefaction of coal to produce synthetic gasoline or other liquid fuels, the production of various petrochemical feedstocks from coal, and the production of nitrogen fertilizer from coal. There have been several public statements related to possibly utilizing NGP coal in these processes. For example, the Burlington Northern Corporation has recently announced plans to construct a synthetic nitrogen fertilizer plant using coal near Circle, Montana as a feedstock.

Currently, however, very little technical and economic data exist to permit a convincing analysis of the potential applicability of these processes to NGP coal resources. With the possible exception of fertilizer production, all the potentially economic technologies are only at the bench or small pilot plant stage. A great deal of technical research and development is needed before any meaningful economic analyses and projections can be attempted. It is unlikely that any of these technologies will be widely utilized in commercial production before 1985-1990. The placing of one or more of these new technologies on-stream at some future date will have a significant effect on coal mining levels. For example, it is anticipated that a 100,000 barrel per day (BPD) coal liquefaction plant may consume up to 15 million tons of coal per year. At this time, one can only suggest that there is potentially a significant demand for Northern Great Plains coal as a feedstock for these coal

conversion technologies, particularly beyond 1985. If these technologies do prove economically feasible, the demand for NGP coal will be larger than that reported here.

PART II

COMPARATIVE ANALYSIS:

MONTANA UNIVERSITY AND ALTERNATIVE PROJECTIONS

- A. NGPRP Projections.
- B. Project Independence.
- C. Regional Projections.

PART II

COMPARATIVE ANALYSIS:

MONTANA UNIVERSITY AND ALTERNATIVE PROJECTIONS

Other than the projections described in this report, the only detailed analysis of projected levels of coal development in the Northern Great Plains is found in the Northern Great Plains Resources Program National and Regional Energy Considerations Work Group Report (February, 1974).¹ Since the NGPRP findings must serve as a reference point for our own projections, they will be discussed in the following section with some attempt to isolate their assumptions for comparison within our methodological framework.

In addition to the NGPRP reports, less comprehensive projections of consumption in portions of the Northern Great Plains coal market area are found in the Federal Energy Administration Project Independence Report (November, 1974); in Energy Forecasts for the Pacific Northwest (September, 1975) by Walter Butcher, George Hinman and Paul Swamidas of the Environmental Research Center at Washington State University; and in Water Use and Coal Development in Eastern Montana (Paul Polzin, Bureau of Business and Economic Research, University of Montana, November, 1974). These projections will be compared to the relevant parts of our projection

¹Hereinafter cited as NGPRP (1974). A summary document which contains no changes in the coal projection, entitled Effects of Coal Development in the Northern Great Plains--hereinafter cited as NGPRP (1975)--was completed in April, 1975.

in the second part of this section.

A. NGPRP Projections

The NGPRP projections are compared to this project's findings in Table 28. The NGPRP forecast for coal used in electrical generation falls below our all FGD market bracket except for the NGPRP "high" forecast in 1985 and 2000 (corresponding to our 5% growth). Our coal gasification projections, on the other hand, are much lower.

In order to identify the basis for the difference in these projections, it is necessary to isolate the methodology and assumptions made in the NGPRP report. Their analysis may be divided by consuming sector: (1) household, commercial and industrial; (2) synthetic gas; and (3) electrical generation.

Direct Coal Consumption by the Household, Commercial and Industrial Sectors

Their analysis of this sector is based on an application of Dupree and West's national model, United States Energy Through the Year 2000 (U.S. Department of the Interior, 1972) to the NGP region. Cross-sectional multiple regression analysis was used to establish the connection between population and personal income levels and the level of energy consumption. These historical relationships were then applied to the 1972 OBERS state projections of population, income, and levels of economic activity. The direct contribution of the household, commercial and industrial sector to coal demand was found to be very small: amounting to only two out of 362 tons of coal in the NGPRP intermediate projection for the year 2000.² This supports our approach of ignoring

²NGPRP (1974), p. II-58, Table 5.

TABLE 28

COMPARATIVE COAL SUPPLY FORECASTS

NGPRP and Montana University Coal Demand Study

(Million Short Tons)			
	<u>1980</u>	<u>1985</u>	<u>2000</u>
<u>NGPRP³</u>			
A. <u>Electrical Generation</u>			
Low	91	108	144
Intermediate	107	139	241
High	107	229	666
B. <u>Synthetic Gas</u>			
Low	0	0	0
Intermediate	0	53	121
High	53	153	311
C. <u>Total</u>			
Low	91	108	144
Intermediate	107	192	362
High	160	382	977
<u>Montana University Coal Demand Study⁴</u>			
A. <u>Electrical Generation</u>			
1%	136	108	126
3%	136	137	214
5%	136	173	360
B. <u>Coal Gasification</u>			
Low	0	0	0
Medium	0	0	0
High	0	22.5	22.5

³NGPRP, Effects of Coal Development in the Northern Great Plains, (April, 1975), Table III-12, p. 40

⁴All FGD Market only, constant share to coal assumption on fuel mix.

this aspect of demand for NGP coal.

Synthetic Gas

The projections we have made are generally lower than other contemporary forecasts of gasification activity. We particularly address the differences between this report and that of the Northern Great Plains Resources Program, possibly the most extensive and visible of those other forecasts.

The NGPRP report, Effects of Coal Development in the Northern Great Plains (April, 1975), forecasts three Coal Development Profiles (or scenarios): one "likely," one "high," and one "low." Their most likely projection is for no SNG plants in 1980, seven in 1985, and sixteen in 2000. Their high projection is for seven plants in 1980, thirteen in 1985, and forty-one in 2000. Their low projection predicts no gasification activity up to 2000.

NGPRP's section on gasification is a small part of a much larger report on coal activity in general. Presumably because of its small relative size, little information is given as to the methodology which led to the specific numbers used in the gasification forecasts. This makes comparison difficult. But general assumptions of energy growth and relative prices were made explicit; and on the basis of these, the following comparisons are offered.

First, consider the area of technological certainty. While the NGPRP report is dated April 1975, the synthetic gas component apparently was completed soon after June 1974, when "a number of energy companies" had shown "substantial interest" in NGP gasification and had "invested in research programs and plant development planning." At that time,

they listed over half a dozen announced plants to be built in the area.

At this writing (October, 1975) no plants have gone beyond the planning stage; industry as a whole seems to be waiting for either technological breakthroughs or governmental subsidy. All known projects have been indefinitely shelved. The September 1, 1975, Oil and Gas Journal sums up this attitude: "Commercial and technological uncertainties are too great for financing at this time, given the questions over markets, prices, costs, and performance of facilities once constructed."

A second assumptive difference leading to different conclusions in the two reports regards the question of future supply and demand for natural gas.

NGPRP's energy demand forecasts came from a U.S. Department of the Interior publication, United States Energy Through the Year 2000 (1972). From the total energy demand, gas was allocated a share of the market based on current usage patterns. Characterizing the D.O.I. forecast is a quote from a draft of the NGPRP report: " . . . this forecast is essentially an extrapolation of current trends based on a knowledge of how the various sectors of the economy use energy and how these sectors are growing. It does not deal explicitly with the effect of price changes on the demand and supply of energy resources, and consequently, does not recognize any energy savings or supply increases that could result from persistent increases in energy prices."

The NGPRP gas demand estimate, then, was not tempered by any conception of demand or supply price elasticity. Our assumption is that any price increase, in gas itself via complete or partial deregulation

or in other substitute fuels, will dampen demand. This is an integral part of the M.I.T. Energy Lab econometric model (which we cite), which predicts an average field price in 1980 of \$0.61 (in 1974 dollars). At this point, quantity supplied would equal quantity demanded through increased supplies and decreased usage.

In consideration of potential gas supply, it must be noted that the M.I.T. model is more optimistic concerning supply response to price than is the D.O.I. forecast. In part, this could be due to reliance on differing figures for potential physical supply of gas.

The third area for comparison of the two projections is that of interfuel competition. We note a currently projected price of SNG at slightly under \$3/Mcf (1974 prices) which is supported by recent claims from utilities and the Project Independence Report.

In its comparison of SNG prices with other gas sources, NGPRP used a figure of \$.91-\$1.27/Mcf (1972 dollars) from the U.S. Bureau of Mines. This figure was used to demonstrate SNG's supposed competitiveness with other sources of gaseous fuel. Substitution away from gas to non-gaseous fuels was not considered. Thus the demand for gas (from all sources) was considered perfectly inelastic with respect to price. We qualitatively consider the "switch-overs," such as to electricity (in home use) and to direct coal burning (in industrial use) that would occur at higher gas prices and conclude that gasifying coal would not be competitive in any market except, perhaps, at heavily subsidized prices.

Electrical Generation

The major consuming sector contributing to the demand for NGP coal is, of course, electrical generation. The methodology used by the NGPRP was to determine existing and near-future coal contracts and mining company projections for 1980 coal export from the NGP region. Past this point, Federal Power Commission projections of electrical consumption and fuel share based on electric power company 10-year plans were used.⁵

Note that no price sensitivity is assumed. They consider economic studies of energy price impact such as Chapman et al.⁶ "controversial."⁷ It is a consumption, not a demand, projection. Note also that electric power company plans, not an independent analysis, were the source of the electric projections. The NGPRP tries to bracket the level of development by making "high" and "low" projections. The "high" projections are based on the following assumptions: a loss of access to Canadian natural gas supplies, a lag in nuclear energy development, and a significant reduction in oil imports. In this situation, NGP coal is used to fire electric generators to replace oil and nuclear fueled generation,

⁵Projections based on electric utilities' plans to install capacity are bound to overstate the total electric energy demand and, therefore, the total coal required to fire the generators. Peak load (due to electric heating and air condition) has been growing faster than base load. This "requires" the installation of excess capacity used only to meet peak load. Project Independence Report (FEA, 1974, p. 288) gives some indication of the exaggeration involved. They calculate the capital investment required by 1985 by electric utilities to meet demand growing at, say, 5%. If peak load growth exceeds base load growth by two percentage points, the investment required is \$344.5 billion. If base load growth exceeds peak load growth, the required investment is \$153.7 billion. The former is 2.24 times as large as the latter, but annual cost consumption would be nowhere near that much greater.

⁶NSF-RANN study done by Chapman, Tyrrell, and Mount as summarized in Science, Vol. 178, No. 4062 (November 17, 1972), pp. 703-708.

⁷NGPRP (1974), p. II-54.

and is converted to synthetic natural gas to provide for the projected consumption. The "low" scenario assumes that production in the NGP region will be for regional (NGP) needs only, except for exports satisfying the existing and near-term, foreseeable contracts. An "intermediate" scenario between these two brackets is then also developed. The details of these calculations are described elsewhere.⁸

In order to contrast the NGPRP analysis with our own, it is necessary to isolate the NGPRP assumptions concerning the size of the market for NGP coal, the growth of electrical generation in this market, the share of future electrical generation that will be coal-fired, and the amount of this coal that will be supplied by the NGP states within the market area.

Market Definition

In Table 29, the NGPRP market definition is compared to our project definition. For the intermediate case, NGPRP defined a market including the following electric reliability council regions: SWPP, MAIN, MARCA, and WSCC (see Figure 6).⁹ This market was used only to determine a rate of growth in coal-fired generation to apply to 1980 contract data. (That is, there was no use made of this market as a basis for total demand.) Based on 1972 generation figures, this market is 93% as large as our all FGD market.

The other market defined by NGPRP was used in the "high" projection to reallocate a reduction in estimated nuclear fueled generation to provide an increase in coal-fired capacity. This market area included

⁸Thomas Power, Working Paper #1, pp. 7-14.
⁹Discussed NGPRP (1974), p. II-55, 56.

TABLE 29

COMPARISON NGPRP AND MONTANA UNIVERSITY COAL DEMAND STUDY
MARKET DEFINITIONS

<u>Total</u>	<u>1972 Generation (billion KWH)</u>
<u>A. NGPRP Market</u>	
1. Intermediate Projection Market Definition ¹⁰	660.1 ¹²
2. High Projection Market Definition ¹¹	536.1 ¹²
<u>B. Montana University Coal Demand Study</u>	
1. All FGD Market	703.8 ¹³
2. All SCS Market	375.4 ¹³
<u>C. Comparison</u>	
A-2 as % of B-1	76%
A-1 as % of B-1	93%
B-2 as % of A-2	70%

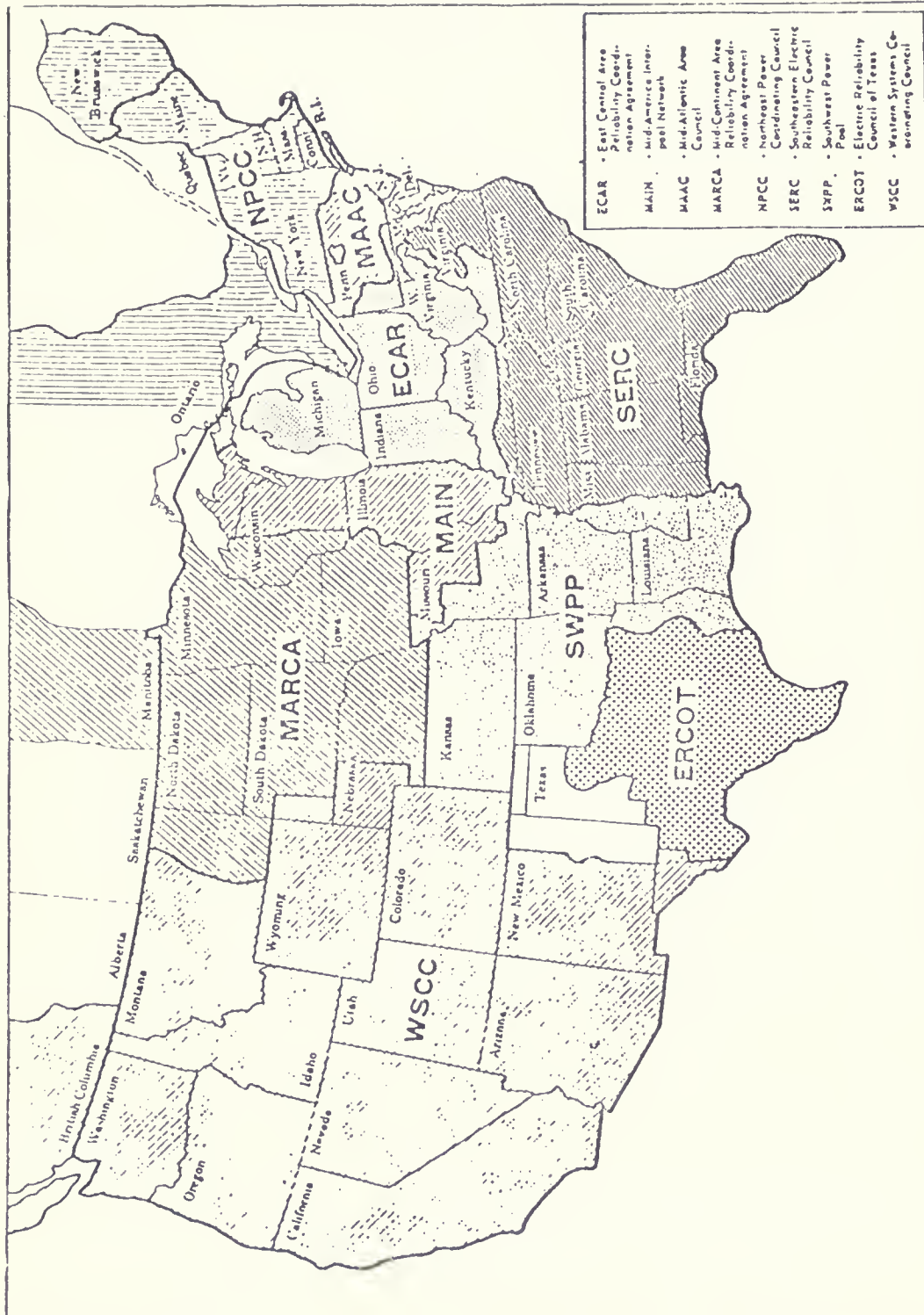
¹⁰As defined pp. II-55,56, NGPRP: SWPP, MAIN, MARCA, WSCC Regional Electric Reliability Councils were used as the basis for the growth rate in coal-fueled capacity.

¹¹NGPRP II-68: one-half MAIN, SWPP, ERCOT, MARCA, one-half WSCC. Regional Electric Reliability Councils were used to allocate the reduction in nuclear capacity.

¹²FPC National Power Survey Task Force on Fuels.

¹³Derived from Edison Electric Institute, Statistical Year Book of the Electric Utility Industry, Table 135.

FIGURE 6
REGIONAL ELECTRIC RELIABILITY COUNCILS



August 1, 1972

REGIONAL ELECTRIC RELIABILITY COUNCILS

Source: Northern Great Plains Resources Program, "National and Regional Energy Considerations Work Group Report," Discussion Draft, February, 1974 p. II-57

one-half MAIN, SWPP, ERCOT, MARCA, and one-half WSCC.¹⁴ Based on 1972 generation, this market is 70% of our All FGD market, the major difference being that ours includes all of MAIN and the states of Indiana and Michigan in ECAR. Based on the way the "markets" were used in the NGPRP study, the "high projection market" appears to correspond most closely to our definition of the market for Northern Great Plains coal.

The basis for a market boundary extending to Illinois is discussed in the April 1975 NGPRP Summary Report. Table 30 following presents the NGPRP calculations which show that only when the cost of flue-gas desulfurization for Illinois coal is taken into account is NGP coal competitive in Illinois-Indiana. This result is compatible with the findings of our market definition model,¹⁵ which identifies the exact geographic NGP coal market boundary for a range of transportation and production costs and environmental standards.

The assumptions which underlie the NGPRP calculation shown in Table 30 can be compared to the parameters used in our market model. As can be seen in Table 31, the NGPRP assumptions about these parameters tend to be lower than ours. For example, the NGPRP report uses a price range for Wyoming coal of \$2.68-\$3.57/ton, while we use a range of \$5.00-\$6.00. (The NGPRP report notes that current contracts are being made at \$5.00/ton.)

Contract Information

Both NGPRP and our projections for 1980 are based on existing contract information. The NGPRP formal listing of contract totals is

¹⁴NGPRP (1974), p. II-68.

¹⁵Terry Wheeling, Working Paper #3.

TABLE 30
PRICE OF NGP COAL IN MIDWEST MARKETS COMPARED TO
PRICES OF MIDWEST COAL

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Origins, destinations and transport mode	Actual cost of trans- portation by unit	Cost of transporta- tion by slurry*	1973 coal cost f.o.b. mine in origin state, cents/10 ⁶ Btu	Estimated average total cost of western coal deliv- ered to state, cents/10 ⁶ Btu	November 1973 actual price of midwestern coal pur- chased by steam-elec- tric plants in state destinations cents/10 ⁶ Btu	Difference in cents/10 ⁶ Btu of NGP coal deliv- ered com- pared to midwestern coal delivered	Cost of stack gas cleaning†	Price advan- tage of NGP coal in cents/10 ⁶ Btu, deliv- ered com- pared to midwestern coal deliv- ered with emission controls
	Range Average							
Montana to Minnesota (approx. 815 miles) Unit train Slurry	18.6 to 31.6 24.5	+ 14.6	+ 16.2 = + 16.2 =	40.7 30.8	-39.6 39.6	1.1 more + 8.8 less +	15.7 = 15.7 =	18 less 28 less
Wyoming to Minnesota (approx. 1,100 miles) Unit train Slurry	30.5 to 32.1 31.3	+ 19.8	+ 16.2 = + 16.2 =	52.8 41.3	39.6 39.6	13.2 more + 1.7 more +	15.7 = 15.7 =	6.1 less 17.6 less
Montana to Ill.-Ind. (approx. 1,270 miles) Unit train Slurry	45.4 to 51.7 49.2	+ 22.9	+ 16.2 = + 16.2 =	65.4 39.1	46.4 46.4	19.0 more + 7.3 less +	15.7 = 15.7 =	0.3 less 26.6 less
Wyoming to Illinois (approx. 1,110 miles) Unit train Slurry	42.5 to 45.0 43.7	+ 20.0	+ 21.5 = + 21.5 =	65.2 41.5	46.4 46.4	18.3 more + 4.9 less +	15.7 = 15.7 =	0.5 less 24.2 less

*Based on 1.8 cents/million Btu/100 miles: 15 million ton/year capacity: 16.8 million Btu/ton. For 3 million ton/year capacity, the cost would be 5.3 cents/million Btu/100 miles. These estimates are modified from the Southwest Energy Study to reflect the Btu value of NGP coal.

†Sulfur Oxide Central Technology Assessment Panel—April 1973. Reflects costs of wet lime/limestone/Ca(OH)₂ slurry scrubbing. Number cited reflected average of 1.1-2.2

mills/kWhr adjusted by heat rate of 10,494 Btu/kWhr 1.65 mills/kWhr x 10⁶ = 157 mills/10⁶ Btu = 15.7 cents/10⁶ Btu
10,494 Btu/kWhr

Source: Northern Great Plains Resources Program, "Effects of Coal
Development in the Northern Great Plains," April, 1975
p. 28

TABLE 31

COMPARISON OF MARKET DEFINITION PARAMETERS:
MONTANA UNIVERSITY COAL DEMAND STUDY AND NGPRP

	<u>Montana University Coal Demand Study</u> ¹⁶	<u>NGPRP</u>
1. <u>Coal Production Prices</u> (\$/ton)		
Illinois	10.00	9.10-10.67 ¹⁷
North Dakota	2.50	
Wyoming	5.00-6.00	2.68- 3.57 ¹⁸
2. <u>Rail Transportation</u> (\$/ton-rail mile)		
1974	.007	.0041-.0066 ¹⁹
1980	.00836	
3. <u>Stack Gas Cleaning</u> (MTs/KWH)		
a. Scrubber - New Source	3.2	1.65 ²⁰
" - Retrofit	4.0	2.47-4.12 ²¹
b. ICS/tall stack	.38	

¹⁶Terry Wheeling, Working Paper #3.

¹⁷39.6-46.4¢/million BTU at 23 million BTU/ton or 11,500 BTU/lb.

¹⁸16.2-21.5¢/million BTU at 8,300 BTU/lb.

¹⁹NGPRP (1975), p. 33, 2.5-4.0¢/million BTU-100 miles at 8,300 BTU/lb.

²⁰Ibid., p. 28; is close to our 1.5 mls/KWH or 1.7 mls/KWH for operating or capital costs alone (respectively).

²¹Ibid., p. 31; based on an observation that retrofit will be 1.5 to 2.5 times as expensive.

summarized in Table 32 and compared to our data. The actual numbers used in the NGPRP projection are inexplicably higher than their published contract data. The NGPRP contract information is low compared to ours, 107 million tons total for 1980 compared to our 135.7 million tons.

Growth in Electrical Generation

After 1980, coal production in both studies is related to the increase in electrical generation, therefore the assumption concerning annual growth in electrical consumption is critical. Our first approach was to bracket this parameter with alternatives of 1%, 3% and 5% annual growth in electrical consumption. The NGPRP, based on FPC estimates, used 7.5% growth to 1980, 6.9% for 1980-85, and 5.8% for 1985-2000 -- considerably higher than our upper estimate of 5% (see Table 33). As suggested previously, no price-sensitivity is presumed in the FPC numbers.

Fuel Mix

It is also critical to the projection to estimate the share of electric generation that will be coal-fired (see Table 34). The NGPRP intermediate estimate called for a declining share of coal-fired generation from 34.2% in 1980 to 15.6% in 2000.²² The NGPRP high estimate of coal generation was for 34% declining to 28.4%. Both assumptions are lower than our constant share (39%) or residual share (approximately 50%).

²²Note: The fuel share assumption was not made explicit in the NGPRP report but, rather, fuel share was adjusted between intermediate and high projection by a shift of nuclear capacity (a drop of about 7.1% in 1985 and 20% in 2000) to coal.

TABLE 32

COMPARISON OF COAL PRODUCTION CONTRACTS:
NGPRP AND MONTANA UNIVERSITY COAL DEMAND STUDY

(Millions of Tons)		
<u>NGPRP</u>		
A. <u>Production</u>	<u>1975</u>	<u>1980</u>
North Dakota	11.67	14.67
Wyoming (Powder River Basin only)	6.35	28.8
Montana	19.82	40.64
<u>Total</u>	37.84	84.11 ²³
B. <u>Contracts for Out-of-State Coal Shipment</u>		
North Dakota		.45
Wyoming		33.0
Montana		28.3
<u>Total</u>		61.75 ²⁴
<u>Montana University Coal Demand Study</u>		
North Dakota		14.0
Wyoming		84.3
Montana		37.5
<u>Total</u>		135.7

²³Derived NGPRP (1974), pp. II-141, II-143. Note: 107 million tons was actually used in the NGPRP intermediate projection.

²⁴Compared with 66 million tons actually used in the NGPRP intermediate projection based on an increase in the rate of coal-fueled generating capacity in the market region. The Montana University Coal Demand Study export number is 87.7 million tons.

TABLE 33

NGPRP ELECTRICAL GENERATION GROWTH ASSUMPTIONS

	<u>1971</u>	<u>1972</u>	<u>1980</u>	<u>1985</u>	<u>2000</u>
A. <u>NGP Region</u>					
Billion KWH ²⁵	41.5		95.2	121.7	316.7
Percentage growth		9.2%	4.9%	6.3%	
B. <u>NGPRP Market Area</u> ²⁶					
Billion KWH		536.1 ²⁷	979.5 ²⁸	1385.8 ²⁸	3330.2 ²⁸
Percentage growth		7.5%	6.9%	5.8%	

²⁵NGPRP (1974), Table 31, App. II-A, p. II-106.

²⁶One-half MAIN, one-half WSCC, SWPP, ERCOT and MARCA Regional Reliability Councils.

²⁷Derived from Chapman, et al., Power Generation (FPC data), Table 4.

²⁸Derived from FPC, Report of the Technical Advisory Committee on Fuel (September, 1974), pp. 67-77.

TABLE 34

COMPARISON OF PROJECTIONS:

MONTANA UNIVERSITY COAL DEMAND STUDY AND NGPRP

		Coal-fired Share of Total Electrical Generation (%)		
		<u>1980</u>	<u>1985</u>	<u>2000</u>
A.	<u>Montana University Coal Demand Study Projections</u> ²⁹			
1.	Constant 1973 Share to Coal Assumption	39.0%	39.0%	39.0%
2.	Residual Share to Coal Assumption	50.3%	44.7%	46.8%
B.	<u>NGPRP Projections</u>			
1.	Intermediate Share Projection	34.2%	29.1%	15.6%
2.	High Share Projection	34.2%	30.9%	28.4%

²⁹All FGD Market at 5% growth.

One of the major differences in the fuel mix assumptions is the high share of future capacity allocated by NGPRP to nuclear-fueled generation (50.9% in the high projection and 63.6% in the intermediate in the year 2000). This compares to our allocation of approximately 34% of year 2000 generation to nuclear fuel for the All FGD market at either 1%, 3%, or 5% growth.

In terms of actual generation, NGPRP forecasts 1695-2119 billion kilowatt/hours of nuclear generation in the year 2000, compared to our 379-1010 kilowatt/hours in the All FGD market at 1% to 5% growth. The NGPRP high projection is more than double our 5% growth All FGD market for 2000 (Table 35). [The reader may wish to refer to our Working Paper #7 for a further discussion of nuclear generation.]

Coal Source

Once the level of coal-fired generation has been established in the market area, it remains to allocate this demand for coal among alternative market sources. The fuel source assumptions used in the Montana University Coal Demand Study were to allocate all of the increase in coal-fired generation in the NGP market area to NGP coal or, alternatively, to assume that the NGP continues to supply coal based on its 1980 contract share (see Table 36).

As suggested earlier, NGPRP used their market definition only in allocating a shift in nuclear capacity in the high case--where they assumed 100% of the increase in coal-fired generating capacity would be supplied by NGP coal.

TABLE 35

COMPARISON OF NUCLEAR PROJECTIONS:
NGPRP AND MONTANA UNIVERSITY COAL DEMAND STUDY

		(Billions of KWH Generation)		
		<u>1980</u>	<u>1985</u>	<u>2000</u>
A. <u>NGPRP "High Projection" Market Area - one-half MAIN, SWPP, ERCOT, MARCA, one-half WSCC market</u> ³⁰				
Intermediate			349.5	2119.3
High			324.7	1695.4
B. <u>Montana University Coal Demand Study Projection</u> ³¹				
All FGD Market				
1%	(Annual Rate of Growth	98.0	308.0	378.6 ³²
3%	(in Electrical	98.0	308.0	596.7 ³²
5%	(Consumption	98.0	308.0	1010.2 ³²

³⁰Based on a load factor of 61.3 in 1985 and 69.2 in 2000 [from NGPRP (1974), II-106].

³¹Based on McBride, Working Paper # 7.

³²Assumes 50% of new electrical growth is allocated to nuclear fuel in 1986-2000.

TABLE 36

COMPARISON OF COAL SOURCE PROJECTIONS
FOR THE NGP COAL MARKET AREA:

NGPRP AND MONTANA UNIVERSITY COAL DEMAND STUDY

	<u>Annual Rate of Growth in Electrical Generation</u>	<u>Share</u> ³³
A. <u>Montana University Coal Demand Study Projection</u> ³⁴		
1. NGP Supplies all Coal used in its Market Area		100%
2. NGP Supplies 1980-based Contract Share of:		
a. Constant share to coal	1%	88%
vis-a-vis	3%	77%
Other fuels	5%	67%
b. Residual share to coal	1%	99%
vis-a-vis	3%	69%
Other fuels	5%	52%
B. <u>NGPRP Projection</u>		
1. Intermediate Projection - MAIN, SWPP, MARCA, WSCC market		100%
2. High Projection - one-half MAIN, SWPP, ERCOT, MARCA, one-half WSCC market		100%

³³Share of total coal used in the market area for electrical generation.

³⁴All FGD market.

Summary

Table 37 summarizes the key assumptions in comparing our projection with NGPRP. As can be seen, NGPRP estimates of market size, 1980 coal contracts, and coal-fired share of total generation are lower than those of the Montana University Coal Demand Study. The NGPRP estimates of total electrical generation growth, nuclear generation, and market share are higher than ours. Hence the NGPRP projections are somewhat lower than the Montana University Coal Demand Study for the years 1980 and 1985.

However, in the year 2000, after the NGPRP extremely high estimate of total electrical generation growth has had an effect, their estimates are on the upper end of our range. If the Montana University Coal Demand Study methodology were the same as that of the NGPRP, by multiplying the ratio of the assumptions in each projection one should be able to get the same ratio as that between the projections themselves. This is done in Table 38 for the year 2000, comparing the NGPRP intermediate projections to our 3% (constant share to coal) projection ($246 \text{ tons}/252 \text{ tons} = .96$), and the NGPRP high projection to our 5% (residual share to coal) projection ($666/334.7 = 1.95$).

1. Market Definition (based on 1972 electrical generation) (billion KWH)	Montana University Coal Demand Study (All FGD Market Only)			Ratio NGPRP/Montana University Coal Demand Study Intermediate/3% ³⁵ High/5% ³⁶	
	Low	Intermediate	High	1% 3% 5%	
2. Electrical Generation Growth (annual growth rate)	-	660.1	536.1	703.8	.93 .76
3. Coal Contracts to 1980 (million tons/yr)					
Export		66	66	85.5	.75
Total	91	107	107	135.7	.77
4. Fuel Mix: Projected Share to Coal (% of total electrical generation)					
1980		34.2	34.2	39.0 ³⁵	.88
1985		29.1	30.9	39.0 ³⁵	.75
2000		15.6	28.4	39.0 ³⁵	.40
5. Projected Nuclear Generation (billion KWH)					
1985		349.5	324.7	308.0	1.13
2000		2119.3	1695.4	596.7	3.55
6. Market Share to NGP Coal					
2000		100%	100%	88% ³⁵ 99% ³⁶	1.30
				77% ³⁵ 69% ³⁶	1.89

³⁵Constant Share to Coal Assumption.
³⁶Residual Share to Coal Assumption.
³⁷7% used for NGPRP average.
³⁸Ratio in the year 2000 of generation increasing at the rate of 7% since 1980 to generation increasing at a rate of 3%: 3.86/1.80.
³⁹Ratio of 7% generation to 5% in the year 2000: 3.86/2.65.

TABLE 38

COMPARISON OF ASSUMPTIONS FOR SPECIFIC YEAR 2000 PROJECTIONS:

NGPRP AND MONTANA UNIVERSITY COAL DEMAND STUDY

(Ratio NGPRP/Montana University Coal Demand Study)

<u>Projection</u>	<u>Market</u>	<u>Electrical Generation</u>	<u>Contracts</u>	<u>Fuel Mix</u>	<u>Share</u>	<u>Product</u>
Ratio <u>Intermediate</u> 3%	(.93)	(2.14)	(.77)	(.40)	(1.30)	= .78
Ratio <u>High</u> 5%	(.76)	(1.45)	(.77)	(.61)	(1.89)	= .98

As can be seen, the product of these ratios is close to the ratio of the actual projections for the intermediate vs. 3% case (.78 vs. .95) but off by a factor of two for the high vs. 5% case (.98 vs. 1.95). This difference can be attributed to the inconsistent way in which NGPRP uses its definition of the market for NGP coal--making ad hoc adjustments to get a high projection.

B. Project Independence

FEA's "Project Independence" has produced thousands of pages of documents. But the formal model that was used in its projections has yet to be published (November, 1975). One has to depend upon the general (non-technical) discussion in the Project Independence Report (FEA, 1974) despite the gaps and inconsistencies in that 800-page document. The Project Independence Report (PIR) attempts to project to the year 1985 what both the supply and demand for all energy resources will be. In that regard it

deals with both a more contained and a much broader problem than that we have focused on. In a brief section, the PIR looks beyond 1985. The following comments will focus on its coal and electric energy aspects.

The PIR's model can be broken into three parts: Data Resources Incorporated, a Cambridge consulting firm built around Harvard and MIT economists, Dale Jorgenson, E.A. Hudson, et al., put together a macro-economic model⁴⁰ which specified for selected years to 1985 the level and sectoral distribution of GNP, unemployment rate, rate of inflation, population, real personal disposal income, etc. The output from this macro model then became the input to separate supply and demand models. There is no feedback between the supply and demand model and the macro model. As a result, rising energy prices cannot affect the rate of growth of the economy.⁴¹

⁴⁰For further details of the Hudson-Jorgenson model, see Thomas Power, Working Paper #1.

⁴¹This assumption is one of the many inconsistencies in the PIR. On pp. 319-320 the results of feeding higher energy prices into a price-sensitive input-output macroeconomic model are reported. The impact of \$11/barrel oil as opposed to \$7/barrel oil is to reduce the expected rate of growth of GNP 1973-80 from 3.8% to 2.8%. By 1985, however, the impact is reduced somewhat so that the 1973-85 growth rate is reduced by only one-half of that percentage point. The impact is entirely through worker productivity.

FEA's consultants, Data Resources Incorporated, were also the Ford Foundation Energy Policy Project's consultants. They argue (see Hudson and Jorgenson, "Energy in the United States: Projections and Policy," 1974, p. 473) that the impact of a "Zero Energy Growth" policy would only reduce real income by 4% in the year 2000 as compared to what the GNP would be under the "Historical Growth" pattern of energy consumption. The specification was for constant elasticity.

The demand model consisted of equations for each energy type by region and for household, industrial-commercial, and transportation sectors. The demand was made a function of the price of the energy type as well as the price of alternative fuels, per capita income, level of industrial activity, the stock of equipment, appliances, houses, the size of the population, etc. These equations were estimated econometrically with lagged variables so that short and long run elasticities could be estimated.

The supply model was a linear programming model which minimized the cost of supplying any given pattern of regional demand for fuels given a broad range of manpower, capital, material, fuel production cost schedules and transportation cost constraints.

The demand and supply models were integrated in a crude iterative process. First, a given set of fuel prices was used to generate a pattern of "unconstrained" demand (by fuel, sector, and region). Then the linear programming supply model generated the least cost supply solution to this demand pattern. The minimum supply prices required for this solution were then compared with the prices assumed to generate the demand pattern. If they were different, the demand prices were moved towards the supply prices and these new prices were used in the demand equations to generate a new demand pattern given the own and cross price elasticities in the demand model. Again, supply and demand prices were compared and the iterative process continued. The results are an equilibrium, consistent, regional supply and demand pattern for each fuel. In particular, the flow of coal from the NGP region to other regions for electrical generation is calculated as well as the use of that coal for other purposes.

The actual coal production forecasts in the PIR are summarized in Table 39. The projection of the previously discussed econometric model is for 36.9 million tons/year to be exported from the NGP region in 1985. This coal flows entirely to the MARCA regional reliability council (in other words, no farther east than Minnesota and Western Wisconsin). This projection is much lower than any of our All FGD market projections and, in fact, is lower than our residual estimate for 1% growth and contract-based share of the potential market. However, whether flue gas desulfurization costs were the basis of the PIR projection is not made clear.⁴²

PIR also published coal production potential estimates (Table 40). These estimates (as summarized in Table 41) for "business as usual" and "accelerated" scenarios fall within the range of our All FGD market projection. Unfortunately, the basis of these projections is not spelled out in the report, and in fact appear to be an estimate of the upper reaches of supply curve, i.e., an answer to the question "how much coal could we produce at most" rather than "how much will be produced." This table is evidently based on the work of the PIR Coal Task Force. The closest they come to explaining their methodology is the following quotation:

⁴²The PIR coal "flows" from the NGP, and our NGP coal "production" for electrical generation projections cannot be directly compared because the use of NGP coal within the NGP must be added to the coal exports to get total production within the NGP (for electrical generation). Tables 19 and 20, pages 56 and 57, indicate that about 36% of NGP production will be for use in NGP states in 1980 (50 of 140 million tons). If an adjustment of this magnitude were made in the above PIR "flow" figure, total NGP production for electric generation would be 57.6 million tons.

TABLE 39

COMPARISON OF PRODUCTION FORECASTS 1980-2000:

• PROJECT INDEPENDENCE REPORT AND
MONTANA UNIVERSITY COAL DEMAND STUDY

(Millions of tons)				
	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
A. <u>Project Independence</u>				
1. Coal Production Potential ⁴³				
Business as Usual	101.6	155.1	188.1	
Accelerated	186.8	303.8	382.1	
2. Coal flows by Originating Region ⁴⁴		36.9		
B. <u>Montana University Coal Demand Study</u>				
All FGD Market (Constant Share to Coal)				
1% growth	136	109		126
3% growth	136	137		214
5% growth	136	173		360
Partial FGD Market				
1% growth	136	34		52

⁴³PIR (November, 1974), Table II-21, p. 108.

⁴⁴Ibid., Table V-17, p. 275.

TABLE 40

COAL PRODUCTION POTENTIAL (MILLION TONS)

REGION	MINE TYPE	1977	Business As Usual 1980	1990	1977	Accelerated 1980	1990
Northern Appalachia	Surface	02.1	91.2	107.5	138.1	135.6	192.2
	Deep	118.7	123.4	135.9	145.8	177.4	267.0
	TOTAL	200.8	216.6	243.4	283.9	313.0	459.2
Southern Appalachia	Surface	92.6	111.0	137.2	164.6	166.6	245.1
	Deep	171.6	195.3	237.0	273.0	300.1	445.6
	TOTAL	264.2	306.3	374.2	437.6	466.7	690.7
Midwestern	Surface	118.8	133.7	159.1	187.9	196.5	287.7
	Deep	50.5	61.4	68.1	80.2	91.6	116.0
	TOTAL	177.3	197.1	227.2	268.1	208.1	423.7
Gulf	Surface	11.2	28.9	42.5	54.0	50.0	75.0
	Deep	-	-	-	-	-	-
	TOTAL	11.2	28.9	42.5	54.0	50.0	75.0
Northern Great Plains	Surface	64.4	99.6	152.0	184.5	185.9	302.6
	Deep	1.3	2.0	3.1	3.6	.9	1.2
	TOTAL	65.7	101.6	155.1	188.1	186.8	303.8
Rocky Mountain	Surface	16.9	19.8	24.4	28.8	29.9	49.4
	Deep	10.8	12.3	14.7	17.3	18.1	27.2
	TOTAL	27.7	32.1	39.1	46.1	48.0	76.6
Pacific Coast	Surface	7.9	12.3	18.5	21.9	23.1	33.0
	Deep	.1	.1	.2	.2	.2	.4
	TOTAL	8.0	12.4	18.7	22.1	23.3	33.4
National	Surface	393.9	498.5	641.2	779.8	787.6	1185.8
	Deep	261.0	396.5	459.0	520.1	588.3	877.3
	TOTAL	754.9	895.0	1100.2	1299.9	1375.9	2063.1

Source: Federal Energy Administration, Project Independence Report, November, 1974, p. 108

TABLE 41

COMPARISON OF PROJECT INDEPENDENCE REPORT
"PRODUCTION POTENTIAL" AND "COAL FLOWS" ESTIMATES

<u>Region</u>	Base Case ⁴⁵ <u>Flows</u>	<u>Percentage</u>	BAU ⁴⁶ <u>Production Potential</u>	<u>Percentage</u>
Northern Appalachia	169.7	16	243.4	22
Southern Appalachia	222.7	21	374.2	34
Interior	465.3	43	227.2	21
Gulf	35.0	3	42.5	4
Northern Great Plains	36.9	3	155.1	14
Rocky Mountain	13.1	1	39.1	4
Pacific Coast	134.4	13	18.7	2
Total	1082.1	100	1100.2	100

⁴⁵Derived PIR, Table V-17, p. 275.

⁴⁶Ibid., Table II-21, p. 108.

*The method of establishing production levels under the two scenarios relied more heavily upon "knowledge of the industry" than it did upon a demonstrable technique. While the estimating technique can be debated, in the light of the size of the Demonstrated Coal Reserve Base of the United States the production levels could be set substantially higher without invoking a supply constraint. The approach also presupposed an increase in productive capacity in 1973 and 1974 that may or may not be accurate, but the differences between assumption and fact are not large enough to bias the study.*⁴⁷

Similarly, in the main PIR under "Major Findings" it is noted that:

The coal industry has the capacity to satisfy almost any foreseeable demand for coal by 1985, at prices near 1972-1973 levels and considerably below current spot market levels. To the extent that investment decisions will have to be made in the immediate future to achieve long-range production goals, a sufficient return on investment and resolution of major uncertainties will be needed. Since unconstrained maximum production levels could be very high, Business-As-Usual and Accelerated Development scenarios were developed so that demand and resource constraints would limit supply. Under BAU, and certainly under AD, production potential exceeds most estimates of demand.

If one assumes then that the 36 million tons/year out of the NGP is the PIR "serious" projection, where both supply and demand are taken into account, their projection is markedly low. Thirty-six million tons in 1985 is only 25% of our estimate for firm 1980 contracts.

Interestingly, the difference between the "productive potentials" of the regions and the projections of coal "flows" from the regions is not due to differences in the assumed total national coal productions.

⁴⁷ FEA, Project Independence Blueprint, Final Task Force Report, Coal (November, 1974), p. 19.

It may be concluded that PIR seriously misestimates the market for NGP coal. In passing, it may be noted that their projection for electric energy demand growth is high for 1973-1985, at 6.5%, but drops to 2% in 1985-2000.⁴⁸ This offers some support for the "stepped" growth rates produced by our price-sensitive model. We also attempted to compare PIR electrical utility coal consumption estimates to ours on a similar basis. For a market which is 91% of our All FGD market, they project a demand for 237 million tons/year in 1985.⁴⁹ This is larger than our estimates for 158-173 million tons at 3%-5% growth and constant share to coal fuel mix.

Further discussions of PIR electrical generation and total energy growth analyses may be found elsewhere.⁵⁰

C. Regional Projections

The only other independent projections concerning NGP coal are for sub-regions of the total market area. As mentioned earlier, Paul Polzin at the University of Montana has projected coal development for Eastern Montana, and Hinman et al., at Washington State University, have projected the demand for coal and uranium in Idaho, Oregon and Washington. These reports are discussed below.

Polzin - Eastern Montana

Polzin's Water Use and Coal Development in Eastern Montana (November, 1974) is primarily an analysis of the socio-economic impact associated with coal development. Out of a 160-page report, only four pages

⁴⁸PIR, pp. 430-35, and 127.

⁴⁹Derived PIR Appendix, pp. 274-275.

⁵⁰Thomas Power, Working Paper #1, pp. 14-31.

are devoted to identifying the likely level of development on which to base the impact analysis. Polzin's results are summarized in Table 42 and compared to our projections for Montana in Table 43. Polzin's 1980 projection for non-gasification coal is 49 million tons, higher than our 1980 estimate of firm contracts. His 1985 projection of 61 million tons is also above our 3% and 5% growth range for the market.

Polzin's estimate for coal used in Montana is based on the 2,060 MW increase in coal-fired capacity by 1980 based on four plants proposed or under construction, plus another 1,000 MW by 1985. These numbers, assuming a load factor of 55.1 (based on FPC estimates for 1985), imply a 8.01% annual growth in electrical generation for 1973-1985 in Montana. According to Polzin, his estimates for export demand are based on "existing long-term contracts for Montana coal and a moderate growth in new demand."⁵¹ The contract information, market assumption, and growth rates are not spelled out. His coal gasification estimates are slightly higher than ours.

To conclude, Polzin's estimate of demand within Montana, based on coal-fired plants currently proposed or under construction, is close to our own. His estimate for export demand, which is not based on extensive analysis, is a reasonable guess, but somewhat above our range.

Butcher, et al. - Pacific Northwest

Walter Butcher and others at the Washington State University Environmental Research Center have made projections of energy consumption

⁵¹Polzin (1974), p. 97.

TABLE 42

PROJECTED ALTERNATIVE LEVELS OF COAL DEVELOPMENT
WITH AND WITHOUT GASIFICATION

1980 AND 1985

	Alternative I (No Gasification)		Alternative II (With Gasification)	
	1980	1985	1980	1985
Montana coal production, total (millions of tons)	49.0	61.0	57.0	77.0
Shipped from Montana	39.5	47.5	39.5	47.5
Used for electrical generation ^a	9.5	13.5	9.5	13.5
Used for gasification	0	0	8.0	16.0
Additional electrical generation (installed megawatts) ^b	2,060	3,060	2,060	3,060
Gasification plants (250 million scfd) ^c	0	0	1	2

^aIncludes 0.5 million tons per year for the Corette plant but excludes 0.33 million tons mined in Richland County (Montana-Dakota Utilities Co.).

^bExcludes the Corette plant.

^cscfd denotes standard cubic feet per day.

Source: Polzin, Paul, "Water Use and Coal Development in Eastern Montana, Montana Joint Water Resources Research Center Report 57, November, 1974, p. 98

TABLE 43

COMPARISON OF PROJECTED COAL PRODUCTION
FOR MONTANA 1980-2000

POLZIN AND MONTANA UNIVERSITY COAL DEMAND STUDY

		(Millions of Tons)		
		<u>1980</u>	<u>1985</u>	<u>2000</u>
A.	<u>Coal for Electrical Generation</u>			
	Montana University Coal Demand Study ⁵²			
	All FGD Market 1%	38	30	35
	Estimate 3%	38	38	59
	5%	38	48	99
	<u>Polzin</u>	49	61	--
B.	<u>Coal Gasification</u>			
	Montana University Coal Demand Study			
	High Projection	0	8	8
	<u>Polzin</u> ⁵³	0	16	--

⁵² Based on 1980 contract share of 27.6% of NGP coal production.

⁵³ Paul E. Polzin, Water Use and Coal Development in Eastern Montana (November, 1974), Table 3.2, p. 98.

for the Pacific Northwest (Washington, Oregon and Idaho).⁵⁴ Their projections are by energy source and consuming sector. Unfortunately for comparative purposes, coal and uranium are lumped together as a fuel source for thermal generation of electricity. Without a specific assumption concerning the future share of generation that will be nuclear (or coal-fired), a specific coal demand forecast cannot be derived. However, it is of interest to compare their electrical generation forecast to our own.

As can be seen from Table 44, their projection for total PNW generation falls between our 1% and 3% growth scenarios. Under their "no price response" projection, generation grows at 2.0% between 1980 and 2000. Under the "low response to \$7 crude" projection, generation grows at 1.8% annually, and under the "high response to \$11 crude," at 1.4%. The specific assumptions here are a long-run price elasticity for electricity of -1.12 and a cross price elasticity with natural gas of .81 and fuel oil of 0.10.⁵⁵ By comparison, our own price elasticity, while state specific, averaged -1.21 for the residential sector, and our natural gas cross price elasticity was substantially lower, 0.13-0.21. These elasticities were used to calculate a correction factor, assumed to have full effect in 1990 [the square root of the correction factor was used in 1980]. The price changes were assumed to be in the near future and were, therefore, not made time dependent. Butcher et al.'s price changes are summarized in Table 45.

⁵⁴Walter Butcher, George Hinman, and Paul Swamidas, Energy Forecasts for the Pacific Northwest (September, 1975). In the discussion below we have only examined their projection based on the OBERS Series E, although they do a Series C scenario also.

⁵⁵ Ibid., Table III-148a.

TABLE 44

COMPARISON OF ELECTRICAL GENERATION PROJECTIONS
FOR THE PACIFIC NORTHWEST:

MONTANA UNIVERSITY COAL DEMAND STUDY AND BUTCHER, ET AL.

		(Billions of KWH)			
		<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
<u>Montana University</u>					
<u>Coal Demand Study</u>					
<u>1% growth</u>	hydro	133.9	136.0		150.0
	thermal	<u>1.3</u>	<u>6.1</u>		<u>15.0</u>
	total	135.2	142.1		165.0
<u>3% growth</u>	hydro	133.9	136.0		150.0
	thermal	<u>21.2</u>	<u>43.8</u>		<u>130.1</u>
	total	155.1	179.8		280.1
<u>5% growth</u>	hydro	133.9	136.0		150.0
	thermal	<u>43.6</u>	<u>90.5</u>		<u>320.8</u>
	total	177.5	226.5		470.8
<u>Butcher, et al., Series E⁵⁶</u>					
<u>No price response</u>					
2.0%	hydro	108.5		108.5	108.5
	thermal	<u>38.1</u>		<u>71.3</u>	<u>110.9</u>
	total	146.6		179.8	219.4
<u>Low response to \$7 crude</u>					
1.8%	hydro	108.5		108.5	108.5
	thermal	<u>38.1</u>		<u>56.9</u>	<u>92.1</u>
	total	141.1		165.4	200.6
<u>High response to \$11 crude</u>					
1.4%	hydro	108.5		108.5	108.5
	thermal	<u>21.1</u>		<u>32.6</u>	<u>61.6</u>
	total	129.6		141.1	170.1

⁵⁶Derived from Butcher, Hinman and Swamidas, Tables III-123 to 146.

TABLE 45

FUTURE PRICES OF ENERGY PRODUCTS IN 1973 DOLLARS

Energy Source	Customer	Ave. 1971 Prices in 1973 Dollars	Future Price Range (1973 Dollars)	Prices for \$7 Oil-Low Response	Prices for \$11 Oil-High Response
Gasoline	Retail	\$.40/gal.	\$.46-.80/gal.	\$.46/gal.	\$.63/gal.
Fuel Oil	Residential	.22/gal.	.27-.46/gal.	.27/gal.	.37/gal.
	Industrial	.11/gal.	.17-.36/gal.	.17/gal.	.27/gal.
Natural Gas	Residential	1.57/Mcf	2.45-3.20/Mcf	2.45/Mcf	3.20/Mcf
	Commercial	1.24/Mcf	2.14-2.90/Mcf	2.14/Mcf	2.90/Mcf
	Industrial	.48/Mcf	1.45-2.20/Mcf	1.45/Mcf	2.20/Mcf
Electricity	Residential	11 mill/kwh	14-20 mill/kwh	14 mill/kwh	20 mill/kwh
	Commercial	12 mill/kwh	15-20 mill/kwh	15 mill/kwh	20 mill/kwh
	Industrial	5.5 mill/kwh	9-13 mill/kwh	9 mill/kwh	13 mill/kwh

Source: Butcher, W., Hinman, G., Swamidas, P.,
 "Energy Forecasts for the Pacific Northwest"
 Environmental Research Center, Washington
 State University, Pullman, Washington
 September, 1975. Table III - 147

For comparison with our own price change assumptions, their price changes can be made time specific. Since they assume no further changes from 1971-2000, on an annual basis (as summarized in Table 46) their electrical price change is .8%-3.0% a year, and their natural gas annual growth rate is 1.5%-5.2%. This is on the low end of our range of 1%, 3%, and 5% growth for electric prices, and 3%, 5%, and 7% growth for natural gas prices. If the price changes are examined on a 1971-1980 basis, their changes are on the high end of our range.

As can be seen from Table 44, the Butcher et al. estimate of hydro-electric generation calls for no change from 1980-2000 (108.5 billion KWH). This is substantially lower than our estimate of 133.9 and 150 billion KWH for 1980 and 2000, respectively.⁵⁷ For some reason, their 1971 base figure of 331 trillion BTU's of hydro generation or 97.1 billion KWH is substantially below the Edison Electric Institute data for that year (113.2 billion KWH), while their total generation figure (112.6 billion KWH) is quite close to the Edison Electric totals (115 billion KWH).

Even without price adjustment, their estimate of electrical generation growth of 2.0% 1980-2000 is substantially lower than FPC estimates of 4.9% annual growth for the Western Systems Coordinating Council region. Their methodology for manufacturing, extractive and commercial sectors was basically to calculate energy consumption per dollar of output and apply this number to the OBERS projection of future earnings in the particular

⁵⁷The Montana University Coal Demand Study does not specifically project hydroelectric generation for the Pacific Northwest. The estimates reported here are based on applying our methodology to published data on existing and potential hydroelectric generating facilities in Washington, Oregon and Idaho.

TABLE 46
GROWTH IN REAL ELECTRIC AND GAS PRICES⁵⁸

	<u>Residential</u>		<u>Commercial</u>		<u>Industrial</u>	
	<u>Low</u>	<u>High</u>	<u>Low</u>	<u>High</u>	<u>Low</u>	<u>High</u>
Electricity						
@ 1971-1980	2.6%	6.6%	2.5%	5.7%	5.4%	9.6%
@ 1971-2000	.8	2.0	.8	1.8	1.7	3.0
Natural Gas						
@ 1971-1980	4.9	7.9	6.0	9.4	12.3	16.9
@ 1971-2000	1.5	2.5	1.9	2.9	3.8	5.2

⁵⁸Derived from Butcher, et al., Table III-147.

sector. They assumed energy per dollar of output was constant except in lumber and wood products, and pulp and paper, where it was assumed to be 30% higher beyond 1980. The residential energy demand was calculated using an appliance saturation model.⁵⁹ The consumption for appliance of type "i" is given by:

$$A_i(t) = A_i^0 N_H(t) S_i(t)$$

where:

$A_i(t)$ = consumption by appliances of type i in year t;

A_i^0 = consumption per appliance of type i;

$N_H(t)$ = household number in year t; and

$S_i(t)$ = fraction of households having appliance i (saturation ratio).

The saturation ratios $S_i(t)$ were assumed to have the form $S_i(t) = 1 - a_i e^{b_i(t-1960)}$ for all electrical appliances except televisions, where $2 - a_{tv} e^{b_{tv}(t-1960)}$ was used. The values of a_i and b_i were found by fitting saturation ratios reported in Merchandising Week. As an example, approximately 43% of all households were estimated to have freezers in 1970, but 67% in 1990.

Obviously, this methodology is quite different from the usual historical projection methodology and results in substantially lower projected growth rates.

To conclude, while Butcher et al. have not developed specific coal

⁵⁹Also discussed in Thomas Power, Working Paper #1, pp. 53-55.

projections, their electrical generation projections using an appliance saturation methodology suggests that future growth may be on the order of 2%. This suggests the plausibility of our low and medium (1% and 3%) assumptions concerning the growth of electrical generation. The parameters used in their price-sensitive projections are roughly comparable to our own.

APPENDIX I

1. PROJECTED ELECTRIC ENERGY GENERATION FOR THE NORTHERN GREAT PLAINS (NGP) COAL MARKET AREA.
2. FUEL MIX PROJECTIONS.
3. COAL SOURCE PROJECTION: ASSUME THAT THE NGP SUPPLIES ALL COAL FOR ELECTRIC GENERATION IN ITS MARKET AREA.
4. COAL SOURCE PROJECTION: ASSUME THAT THE NGP CONTINUES TO SUPPLY ITS 1980 CONTRACT BASED SHARE OF ELECTRIC UTILITY COAL CONSUMPTION.
5. COAL SOURCE PROJECTION: ASSUME THAT THE NGP SUPPLIES ALL COAL FOR NEW ELECTRIC GENERATION IN ITS MARKET AREA.
6. CONSUMPTION OF NGP COAL FOR GASIFICATION.
7. CONSUMPTION OF NGP COAL AS A BOILER FUEL TO REPLACE NATURAL GAS.

APPENDIX I

1. PROJECTED ELECTRIC ENERGY GENERATION FOR THE NORTHERN GREAT PLAINS (NGP) COAL MARKET AREA

TABLE A: *TOTAL ELECTRIC GENERATION FOR THE NGP COAL MARKET AREA*

<u>Market Estimate</u>	<u>Constant Annual Generation Growth Assumption</u>	(Billions of Kilowatt Hrs/Year)			
		<u>1973¹</u>	<u>1980</u>	<u>1985</u>	<u>2000</u>
All FGD	1%	725.9	778.2	817.9	949.6
	3%	725.9	892.8	1035.0	1612.4
	5%	725.9	1021.4	1303.6	2710.1
Partial FGD	1%	373.1	425.4	465.1	596.8
	3%	373.1	540.0	682.2	1259.6
	5%	373.1	668.6	950.8	2357.3
All SCS	1%	373.1	400.0	420.4	488.1
	3%	373.1	458.9	532.0	828.8
	5%	373.1	525.0	670.1	1393.0

2. FUEL MIX PROJECTIONS

TABLE B: *COAL-FIRED GENERATION MAINTAINS ITS CURRENT (1973) SHARE OF ELECTRIC ENERGY PRODUCTION*

<u>Market Estimate</u>	<u>Constant Annual Generation Growth Assumption</u>	(Billions of Kilowatt Hrs/Year)			
		<u>1973</u>	<u>1980</u>	<u>1985</u>	<u>2000</u>
All FGD (39%)	1%	283.4	303.5	319.0	370.3
	3%	283.4	348.2	403.7	628.8
	5%	283.4	398.3	508.4	1056.9
Partial FGD	1%	51.6	71.7	87.2	138.5
	3%	51.6	116.4	171.9	397.0
	5%	51.6	166.5	276.6	825.1
All SCS (13.8%)	1%	51.6	55.2	58.0	67.4
	3%	51.6	63.3	73.4	114.4
	5%	51.6	72.5	92.5	192.2

¹Actual generation based on Edison Electric Institute, Statistical Year Book of the Electric Utility Industry, 1973, Table 13S.

TABLE C: *HYDROELECTRIC GENERATION*²

Market Estimate	Constant Annual Generation Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD		140.8	173.1	177.0	195.7
Partial FGD		129.8	162.1	165.8	184.4
All SCS		129.8	161.8	165.7	182.8

TABLE D: *NUCLEAR FUELED GENERATION*³

Market Estimate	Constant Annual Generation Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD	1%	37.1	98.0	308.0	378.6 ⁴
	3%	37.1	98.0	308.0	596.7
	5%	37.1	98.0	308.0	1010.2
Partial FGD	1%	8.3	69.2	279.2	349.8
	3%	8.3	69.2	279.2	567.9
	5%	8.3	69.2	279.2	981.4
All SCS	1%	8.3	30.0	130.0	159.0
	3%	8.3	30.0	130.0	248.7
	5%	8.3	30.0	130.0	419.2

TABLE E: *SUBTOTAL: HYDROELECTRIC, NUCLEAR, AND GAS FUELED GENERATION*⁵

Market Estimate	Constant Annual Generation Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD	1%	414.4	507.6	721.5	810.8
	3%	414.4	507.6	721.5	1028.9
	5%	414.4	507.6	721.5	1442.4
Partial FGD	1%	315.4	408.6	622.3	711.5
	3%	315.4	408.6	622.3	929.6
	5%	315.4	408.6	622.3	1343.1
All SCS	1%	315.4	369.1	473.0	519.1
	3%	315.4	369.1	473.0	608.8
	5%	315.4	369.1	473.0	779.3

²McBride, Working Paper #6.³McBride, Working Paper #7.⁴Assumes that half of new generation in the years 1985-2000 goes to nuclear fuel in the All FGD market and forty percent of new generation in the All SCS market is nuclear.⁵Assumes gas fired generation is fixed at 1973 levels (for the All FGD market, 236.5 Billion KWH/yr, for the All SCS, 177.3 Billion KWH/yr).

TABLE F: *COAL-FIRED ELECTRIC GENERATION AS A RESIDUAL GIVEN HYDROELECTRIC, NUCLEAR, AND GAS FUELED GENERATION*⁶

Market Estimate	Constant Annual Generation Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD	1%	311.5	270.6	96.4	138.8
	3%	311.5	385.2	313.5	583.5
	5%	311.5	513.8	582.1	1267.7
Partial FGD	1%	57.7	16.8	0	0
	3%	57.7	131.4	59.9	330.0
	5%	57.7	260.0	328.5	1014.0
All SCS	1%	57.7	30.9	0	0
	3%	57.7	89.8	59.0	220.0
	5%	57.7	155.9	197.1	613.7

3. COAL SOURCE PROJECTION: ASSUME THAT THE NGP SUPPLIES
ALL COAL FOR ELECTRIC GENERATION IN ITS MARKET AREA

TABLE G: *COAL PRODUCTION ASSUMING THAT COAL-FIRED GENERATION MAINTAINS ITS CURRENT SHARE OF ELECTRIC ENERGY PRODUCTION*

Market Estimate	Constant Annual Generation Growth Assumption	(Millions of Tons) ⁷			
		1973	1980	1985	2000
All FGD	1%	143.9	154.1	161.9	188.0
	3%	143.9	176.8	204.9	319.2
	5%	143.9	202.2	258.1	536.6
Partial FGD	1%	33.2	43.4	51.2	77.3
	3%	33.2	66.1	94.2	208.5
	5%	33.2	91.5	147.4	425.9
All SCS	1%	33.2	35.5	37.3	43.4
	3%	33.2	40.8	47.3	73.6
	5%	33.2	46.7	59.6	123.7

⁶Assumes 0% share to oil (1973 actual 3.8% and 1.6% in the All FGD and All SCS markets, respectively).

⁷Uses 1973 All FGD market average of 1.9698×10^3 KWH/ton and All SCS market average of 1.5533×10^3 KWH/ton (based on data in FPC News, May 24, 1974, p. 23).

TABLE H: COAL PRODUCTION BASED ON THE ASSUMPTION THAT THE RESIDUAL SHARE OF THE FUEL MIX WITHIN THE NGP MARKET AREA WILL BE FILLED BY COAL-FIRED GENERATION

<u>Market Estimate</u>	<u>Constant Annual Generation Growth Assumption</u>	(Millions of Tons)			
		<u>1973</u>	<u>1980</u>	<u>1985</u>	<u>2000</u>
All FGD	1%	143.9	137.4	48.9	70.5
	3%	143.9	195.6	159.2	296.2
	5%	143.9	260.8	295.5	643.6
Partial FGD	1%	33.2	16.5	0	0
	3%	33.2	74.7	38.3	175.3
	5%	33.2	139.9	174.6	522.7
All SCS	1%	33.2	19.9	0	0
	3%	33.2	57.8	38.0	141.6
	5%	33.2	100.4	126.9	395.1

4. COAL SOURCE PROJECTION: ASSUME THAT THE NGP
CONTINUES TO SUPPLY ITS 1980 CONTRACT-BASED
SHARE OF ELECTRIC UTILITY COAL CONSUMPTION

TABLE I: *COAL PRODUCTION ASSUMING THAT COAL-FIRED GENERATION MAINTAINS ITS CURRENT SHARE OF ELECTRIC ENERGY PRODUCTION*

Market Estimate	Constant Annual Generation Growth Assumption	NGP Coal Market Share	(Millions of Tons)		
			1980	1985 ⁸	2000 ⁸
All FGD	1%	.88	135.7	108.5	126.0
	3%	.77	135.7	137.3	213.8
	5%	.67	135.7	172.9	359.5
Partial FGD ⁹	1%	.88	135.7	34.4	51.8
	3%	.77	135.7	63.1	139.8
	5%	.67	135.7	98.8	285.4
All SCS	1%	2.41	85.5	68.3	79.4
	3%	2.09	85.5	86.6	134.7
	5%	1.83	85.5	109.1	226.4

⁸The 1985 and 2000 estimates are based on the 1980 contract share at the 5% growth rate (i.e., on the share implicit in utilities expectations).

⁹The 1980 All FGD and Partial FGD estimates are the same since it is assumed that all production to be on line in 1980 is already contracted for. No empirical basis for identifying a Partial FGD estimate 1980 based contract share (the share that would obtain if ICS are approved for existing plants) exists, since producers are behaving as though ICS will not be approved. Therefore, to get our 1985 and 2000 Partial FGD estimate, which would result if ICS are approved, we used the All FGD market share as an approximation (applied to Table G). This is probably low since NGP coal would probably have a larger relative share in the smaller market area.

TABLE J: *COAL PRODUCTION BASED ON THE ASSUMPTION THAT THE RESIDUAL SHARE OF THE FUEL MIX WITHIN THE NGP MARKET AREA WILL BE FILLED BY COAL-FIRED GENERATION*

Market Estimate	Constant Annual Generation Growth Assumption	NGP Coal Market Share	(Millions of Tons)		
			1980	1985 ¹⁰	2000 ¹⁰
All FGD	1%	.99	135.7	25.4	36.7
	3%	.69	135.7	82.8	154.0
	5%	.52	135.7	153.7	334.7
Partial FGD	1%	.99	135.7	0	0
	3%	.69	135.7	19.9	91.2
	5%	.52	135.7	90.8	271.8
All SCS	1%	4.29	85.5	0	0
	3%	1.46	85.5	31.9	118.9
	5%	.84	85.5	106.6	331.9

5. COAL SOURCE PROJECTION: ASSUME THAT THE NGP SUPPLIES

ALL COAL FOR NEW ELECTRIC GENERATION IN ITS MARKET AREA

TABLE K: *COAL PRODUCTION ASSUMING THAT COAL-FIRED GENERATION MAINTAINS ITS CURRENT SHARE OF ELECTRIC ENERGY PRODUCTION*

Market Estimate	Constant Annual Generation Growth Assumption	(Millions of Tons)			
		1973 ¹¹	1980	1985	2000
All FGD	1%	32.0	42.2	50.0	76.1
	3%	32.0	64.9	93.0	207.3
	5%	32.0	90.3	146.2	424.7
All SCS	1%	32.0	34.3	36.1	42.2
	3%	32.0	39.6	46.1	72.4
	5%	32.0	45.5	58.4	122.5

The Partial FGD Market Estimate is identical to the All FGD Market Estimate in this configuration.

¹⁰The 1985 and 2000 estimates are based on the 1980 contract share at the 5% growth rate.

¹¹1973 NGP coal production as reported in the Northern Great Plains Resources Program Draft Summary Report, September, 1974.

TABLE L: *COAL PRODUCTION BASED ON THE ASSUMPTION THAT THE RESIDUAL SHARE OF THE FUEL MIX WITHIN THE NGP MARKET AREA WILL BE FILLED BY COAL-FIRED GENERATION*

<u>Market Estimate</u>	<u>Constant Annual Generation Growth Assumption</u>	(Millions of Tons)			
		<u>1973</u>	<u>1980</u>	<u>1985</u>	<u>2000</u>
All FGD	1%	32.0	25.5	0	0
	3%	32.0	83.7	47.3	184.3
	5%	32.0	148.9	183.6	531.7
All SCS	1%	32.0	18.7	0	0
	3%	32.0	56.6	36.8	140.4
	5%	32.0	99.2	125.7	393.9

The Partial FGD Market Estimate is identical to the All FGD Market Estimate in this configuration.

6. CONSUMPTION OF NGP COAL FOR GASIFICATION

TABLE M: *COAL GASIFICATION PROJECTION*¹²

	<u>1980</u>	<u>1985</u>	<u>2000</u>
Number of Plants			
Low	0	0	0
Most likely	0	0	0
High	0	3	3
Millions of Tons of Coal			
Low	0	0	0
Most likely	0	0	0
High	0	22.5	22.5

¹²Richard Stroup and Walter Thurman, Working Paper #2. Assumes 250 MM Scf/day plants using 7.5×10^6 tons/plant-year.

7. CONSUMPTION OF NGP COAL AS A BOILER FUEL
TO REPLACE NATURAL GAS

TABLE N: *COAL REPLACEMENT PROJECTION (COAL PRODUCTION FROM THE NGP TO REPLACE NATURAL GAS SHORTFALLS)*¹³

	(Millions of Tons)		
	<u>1980</u>	<u>1985</u>	<u>2000</u>
Low	0	0	0
Most likely	0	0	0
High	0	16.5-31.3 ¹⁴	33-62.6 ¹⁴

¹³This assumes that the shortfalls are all assigned to industrial users. Increases in industrial demand for Natural Gas in the 21-state market are filled by both NGP coal and midwestern coal. The share of natural gas replacement allocated to NGP coal is the same as the NGP coal-fired generation share. For further details see Montana University Coal Demand Study Working Paper #14 by Walter Thurman and Richard Stroup.

¹⁴The variation in coal production is due to variations in coal production prices. The highest production corresponds to a coal production price of \$5.00/ton while the low corresponds to a production price of \$7.50/ton.

APPENDIX II

1. PRICE-SENSITIVE PROJECTION OF ELECTRIC ENERGY FOR THE NORTHERN GREAT PLAINS (NGP) MARKET AREA.
2. FUEL MIX PROJECTION.
3. COAL SOURCE PROJECTION: ASSUME THAT THE NGP SUPPLIES ALL COAL FOR ELECTRIC GENERATION IN ITS MARKET AREA.
4. COAL SOURCE PROJECTION: ASSUME THAT THE NGP CONTINUES TO SUPPLY ITS 1980 CONTRACT-BASED SHARE OF ELECTRIC UTILITY COAL CONSUMPTION.

APPENDIX II

1. PRICE-SENSITIVE PROJECTION OF ELECTRIC ENERGY GENERATION
FOR THE NORTHERN GREAT PLAINS (NGP) MARKET AREA

TABLE A: *PRICE-SENSITIVE TOTAL ELECTRIC GENERATION FOR THE NGP
COAL MARKET*

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973 ¹	1980	1985	2000
All FGD	0%, 0%	725.9	1081.4	1328.4	2063.6
	FPC, 3%	725.9	1052.5	1251.9	1719.9
	3%, 5%	725.9	955.2	1010.9	890.8
	5%, 7%	725.9	880.1	844.2	516.7
Partial FGD	0%, 0%	373.1	728.6	975.6	1710.8
	FPC, 3%	373.1	699.7	899.1	1367.1
	3%, 5%	373.1	602.4	658.1	538.0
	5%, 7%	373.1	527.3	491.4	163.9
All SCS	0%, 0%	373.1	572.6	710.8	1120.4
	FPC, 3%	373.1	556.6	668.1	926.0
	3%, 5%	373.1	506.0	541.4	482.9
	5%, 7%	373.1	466.1	451.8	280.0

2. FUEL MIX PROJECTION

TABLE B: *PRICE-SENSITIVE COAL-FIRED GENERATION -- COAL MAINTAINS ITS
CURRENT (1973) SHARE OF FUEL MIX*

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD (39%)	0%, 0%	283.1	421.7	518.1	804.8
	FPC, 3%	283.1	410.5	488.2	670.8
	3%, 5%	283.1	372.5	394.3	347.4
	5%, 7%	283.1	343.2	329.2	201.5
Partial FGD	0%, 0%	51.5	190.1	286.5	573.2
	FPC, 3%	51.5	178.9	256.6	439.2
	3%, 5%	51.5	140.9	162.7	115.8
	5%, 7%	51.5	111.6	97.6	0
All SCS (13.8%)	0%, 0%	51.5	79.0	98.1	154.6
	FPC, 3%	51.5	76.8	92.2	127.8
	3%, 5%	51.5	69.8	74.7	66.6
	5%, 7%	51.5	64.3	62.3	38.6

¹Actual generation based on Edison Electric Institute, Statistical Year Book of the Electric Utility Industry, 1973, Table 13S.

TABLE C: *HYDROELECTRIC GENERATION*²

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD		140.8	173.1	177.0	195.7
Partial FGD		129.8	162.1	165.8	184.4
All SCS		129.8	161.8	165.7	182.8

TABLE D: *PRICE-SENSITIVE NUCLEAR-FUELED GENERATION*³

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000 ⁴
All FGD	0%, 0%	37.1	98.0	308.0	675.6
	FPC, 3%	37.1	98.0	308.0	542.0
	3%, 5%	37.1	98.0	308.0	308.0 ⁵
	5%, 7%	37.1	98.0	308.0	308.0 ⁵
Partial FGD	0%, 0%	8.3	69.2	279.2	646.8
	FPC, 3%	8.3	69.2	279.2	513.2
	3%, 5%	8.3	69.2	279.2	279.2 ⁵
	5%, 7%	8.3	69.2	279.2	279.2 ⁵
All SCS	0%, 0%	8.3	30.0	130.0	293.8
	FPC, 3%	8.3	30.0	130.0	233.2
	3%, 5%	8.3	30.0	130.0	130.0 ⁵
	5%, 7%	8.3	30.0	130.0	130.0 ⁵

²McBride, Working Paper #6.³McBride, Working Paper #7.⁴Assumes that half of new generation in the years 1985-2000 goes to nuclear in the All FGD market and forty percent of new generation in the All SCS market is nuclear.⁵Where there is a projected decline in new generation from 1985-2000, it is assumed that nuclear generation is at the 1985 level.

TABLE E: *PRICE-SENSITIVE SUBTOTAL: HYDROELECTRIC, NUCLEAR, AND GAS FUELED GENERATION*⁶

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD	0%, 0%	414.4	507.6	721.5	1107.8
	FPC, 3%	414.4	507.6	721.5	974.2
	3%, 5%	414.4	507.6	721.5	740.2
	5%, 7%	414.4	507.6	721.5	740.2
Partial FGD	0%, 0%	315.4	408.6	622.3	1008.5
	FPC, 3%	315.4	408.6	622.3	874.9
	3%, 5%	315.4	408.6	622.3	640.9
	5%, 7%	315.4	408.6	622.3	640.9
All SCS	0%, 0%	315.4	369.1	473.0	653.9
	FPC, 3%	315.4	369.1	473.0	593.3
	3%, 5%	315.4	369.1	473.0	490.1
	5%, 7%	315.4	369.1	473.0	490.1

TABLE F: *PRICE-SENSITIVE COAL GENERATION AS A RESIDUAL GIVEN HYDROELECTRIC, NUCLEAR AND GAS FUELED GENERATION*⁷

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Billions of Kilowatt Hrs/Year)			
		1973	1980	1985	2000
All FGD	0%, 0%	311.5	573.8	606.9	955.8
	FPC, 3%	311.5	544.9	530.4	745.7
	3%, 5%	311.5	447.6	289.4	150.6
	5%, 7%	311.5	372.5	122.7	0
Partial FGD	0%, 0%	57.7	320.0	353.2	702.3
	FPC, 3%	57.7	291.1	276.7	492.2
	3%, 5%	57.7	193.8	35.7	0
	5%, 7%	57.7	118.7	0	0
All SCS	0%, 0%	57.7	203.5	237.8	466.5
	FPC, 3%	57.7	187.5	195.1	332.7
	3%, 5%	57.7	136.9	68.4	0
	5%, 7%	57.7	97.0	0	0

⁶Assumes gas generation is fixed at 1973 levels (for the All FGD market, 236.5 Billion KWH/yr, for the All SCS, 177.3 Billion KWH/yr).

⁷Assumes 0% share to oil (1973 actual 3.8% and 1.6% in the All FGD and All SCS markets, respectively).

3. COAL SOURCE PROJECTION: ASSUME THAT THE NGP SUPPLIES
ALL COAL FOR ELECTRIC GENERATION IN ITS MARKET AREA

TABLE G: *PRICE-SENSITIVE COAL PRODUCTION ASSUMING THAT COAL-FIRED GENERATION MAINTAINS ITS CURRENT SHARE OF ELECTRIC ENERGY PRODUCTION*

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Millions of Tons) ⁸			
		1973	1980	1985	2000
All FGD	0%, 0%	143.9	214.1	263.0	408.6
	FPC, 3%	143.9	208.4	247.8	340.5
	3%, 5%	143.9	189.1	200.2	176.4
	5%, 7%	143.9	174.2	167.1	102.3
Partial FGD	0%, 0%	33.2	103.4	152.3	297.9
	FPC, 3%	33.2	97.7	137.1	229.8
	3%, 5%	33.2	78.4	89.5	65.7
	5%, 7%	33.2	63.5	56.4	0
All SCS	0%, 0%	33.2	50.9	63.2	99.5
	FPC, 3%	33.2	49.4	59.4	82.3
	3%, 5%	33.2	44.9	48.1	42.9
	5%, 7%	33.2	41.4	40.1	24.9

TABLE H: *PRICE-SENSITIVE COAL PRODUCTION BASED ON THE ASSUMPTION THAT THE RESIDUAL SHARE OF THE FUEL MIX WITHIN THE NGP MARKET AREA WILL BE FILLED BY COAL-FIRED GENERATION*

Market Estimate	Electric-Gas Annual Price Growth Assumption	(Millions of Tons)			
		1973	1980	1985	2000
All FGD	0%, 0%	143.9	291.3	308.1	485.2
	FPC, 3%	143.9	276.6	269.3	387.6
	3%, 5%	143.9	227.2	146.9	76.5
	5%, 7%	143.9	198.1	62.3	0
Partial FGD	0%, 0%	33.2	170.4	187.2	364.3
	FPC, 3%	33.2	155.7	148.4	257.7
	3%, 5%	33.2	106.3	26.0	0
	5%, 7%	33.2	68.2	0	0
All SCS	0%, 0%	33.2	131.0	153.1	300.3
	FPC, 3%	33.2	120.7	125.6	214.2
	3%, 5%	33.2	88.1	44.0	0
	5%, 7%	33.2	62.4	0	0

⁸Uses 1973 All FGD market average of 1.9698×10^3 KWH/ton and All SCS market average of 1.5533×10^3 KWH/ton (based on data in FPC News, May 24, 1974, p. 23).

4. COAL SOURCE PROJECTION: ASSUME THAT THE NGP
CONTINUES TO SUPPLY ITS 1980 CONTRACT-BASED
SHARE OF ELECTRIC UTILITY COAL CONSUMPTION

Table I: *PRICE-SENSITIVE COAL PRODUCTION ASSUMING THAT COAL-FIRED GENERATION MAINTAINS ITS CURRENT SHARE OF ELECTRIC ENERGY PRODUCTION*

Market Estimate	Electric-Gas Annual Price Growth Assumption	NGP Coal Market Share	(Millions of Tons)		
			1980	1985 ⁹	2000 ⁹
All FGD	0%, 0%	.63	135.7	171.0	265.6
	FPC, 3%	.65	135.7	161.1	221.3
	3%, 5%	.72	135.7	130.1	114.7
	5%, 7%	.78	135.7	108.6	66.5
Partial FGD ¹⁰	0%, 0%	.63	135.7	99.0	193.6
	FPC, 3%	.65	135.7	89.1	149.4
	3%, 5%	.72	135.7	58.2	42.7
	5%, 7%	.78	135.7	36.7	0
All SCS	0%, 0%	1.68	85.5	109.3	172.1
	FPC, 3%	1.73	85.5	102.8	142.4
	3%, 5%	1.90	85.5	83.2	74.2
	5%, 7%	2.07	85.5	69.4	43.1

⁹The 1985 and 2000 estimates are based on the 1980 contract share for the (FPC, 3%) price increase permutation.

¹⁰The 1980 All FGD and Partial FGD estimates are the same since it is assumed that all production to be on line in 1980 is already contracted for. No empirical basis for identifying a Partial FGD estimate 1980 based contract share (the share that would obtain if ICS are approved for existing plants) exists, since producers are behaving as though ICS will not be approved. Therefore, to get our 1985 and 2000 Partial FGD estimate, which would result if ICS are approved, we used the All FGD market share as an approximation (applied to Table G). This is probably low since NGP coal would probably have a larger relative share in the smaller market area.

TABLE J: *PRICE-SENSITIVE COAL PRODUCTION BASED ON THE ASSUMPTION THAT THE RESIDUAL SHARE OF THE FUEL MIX WITHIN THE NGP MARKET AREA WILL BE FILLED BY COAL-FIRED GENERATION*

Market Estimate	Electric-Gas Annual Price Growth Assumption	NGP Coal Market Share	(Millions of Tons)		
			1980	1985 ⁹	2000 ⁹
All FGD	0%, 0%	.47	135.7	151.0	237.8
	FPC, 3%	.49	135.7	132.0	185.5
	3%, 5%	.60	135.7	72.0	37.5
	5%, 7%	.72	135.7	30.5	0
Partial FGD ¹⁰	0%, 0%	.47	135.7	91.7	178.5
	FPC, 3%	.49	135.7	72.7	126.3
	3%, 5%	.60	135.7	12.7	0
	5%, 7%	.72	135.7	0	0
All SCS	0%, 0%	.65	85.5	108.7	213.2
	FPC, 3%	.71	85.5	89.2	152.1
	3%, 5%	.97	85.5	31.2	0
	5%, 7%	1.37	85.5	0	0

⁹See Footnote 9, Table I, Appendix II.

¹⁰See Footnote 10, Table I, Appendix II.

A coal source projection using the assumption that the NGP supplies all coal for new electric generation in its market area was not calculated for price-sensitive electric generation. This configuration appears unrealistic based on the results of the constant annual growth projection.

APPENDIX III

1. Methodological Appendix
(Constant Growth Projection)
2. Methodological Appendix
(Price Sensitive Projection)

1. Methodological Appendix--Constant Growth Projection

Definition of Market Areas

The All FGD market area consists of 21 states and corresponds to the situation where air pollution emission controls are required for both old and new coal-fired power plants. These emission controls would require either flue gas desulfurization (we project lime/limestone scrubbing) or the combustion of coal with a sulfur content below $0.6 \text{ lb}/10^6 \text{ BTU}$. The

All SCS market area contains 13 states. It corresponds to the situation where supplementary control systems (tall stacks and/or intermittent control systems) are permitted for all coal-fired power plants. The Partial FGD market area corresponds to the situation where FGD is required for all new coal-fired power plants, but SCS is permitted for old plants. The Partial FGD market is projected for various years by adding the projected growth or decline in the All FGD market to the All SCS 1973 base.

Table A: Total Electric Generation for the NGP Coal Market Area

The 1973 base generation for the market areas was calculated by summing the various state totals within the market areas in the Edison Electric Institute Statistical Year Book of the Electric Utility Industry, 1973, Table 13S. Future projections were made by applying 1%, 3%, and 5% annual growth factors to the market area base generation.

Table B: Fuel Mix Projection: Coal-Fired Generation Maintains its Current Share of Electric Energy Production.

The 1973 base coal-fired electric generation was also calculated from the Edison Electric Institute Statistical Year Book of the Electric Utility Industry. Future projections were made by multiplying the projections in Table A by the current coal-fired generation percentage (39% for the All FGD market and 13.8% for the All SCS market). The Partial FGD market totals were calculated as described in the Definition of Market Areas.

Table C: Hydroelectric Generation

As a first step in calculating hydroelectric generation for the Northern Great Plains coal market areas, a revised January 1974 datum had to be constructed. The Pacific Northwest had a low water year in 1973, hence hydroelectric generation in that year was considerably below average. We suspected that projecting from this anomolous base would lead to spurious results. Revised January 1, 1974 hydroelectric generation data for the market areas were calculated by subtracting the 1973 hydroelectric generation for the States of Washington, Oregon and Idaho from the 1973 market area hydroelectric generation total. The "average" annual generation (F.P.C., 1972) for all dams existing in Washington, Oregon and Idaho on January 1, 1972 was then added to the market area hydroelectric total along with an estimate of the "average" annual generation from all dams completed in Washington, Oregon and Idaho during 1972 and 1973. This "average" for new dams was calculated by multiplying the generating capacity rating of the new dams by 5.76×10^6 KWH/MW, the "average" annual generation per megawatt of capacity for existing dams in the three state region. Projections for future hydroelectric generation within the market area were then made from this datum.

1980

The 1980 hydroelectric generation forecasts for the Northern Great Plains coal market areas are based entirely on published (F.E.A., 1974a) construction time tables for projects currently planned or under construction. It includes both new facilities and capacity additions to existing dams. No construction delays are projected.

1985

The calculation procedure used to generate the 1985 market area forecasts of hydroelectric generation were identical to the 1980 procedures. It should be noted that a large part of the 1985 increase is capacity additions to existing facilities.

2000

The year 2000 forecasts for the hydroelectric generation in Northern Great Plains coal market areas assumed no new capacity additions to existing facilities. The year 2000 forecasts were generated by simply assuming that 60 percent of all new hydroelectric generation coming on line in the United States between 1985 and 2000 would be in the All FGD Northern Great Plains coal market area and that 55 percent would be in the All SCS market area. In actual fact, the All FGD market area contains 61 percent of the potential additional hydroelectric capacity exclusive of Alaska; thus we are projecting that new hydroelectric capacity additions will be proportional to the number of additional sites available. An annual power production to installed capacity ratio of 3.11×10^6 KWH/MW was used to convert generating capacity to annual generation. This is the actual ratio for all remaining hydroelectric sites in the All FGD market area.

Table D: Nuclear Fueled Generation1980

The 1980 generating capacity estimates for the All FGD and All SCS markets are 90 percent of the generating capacity scheduled to be on line by 1980 in the respective states included in the market areas. Total power production from these plants was calculated using a 60 percent capacity factor.

1985

The 1985 generating capacity estimates for the All FGD and All SCS markets again are 90 percent of the scheduled generating capacity for the states included in the two market areas. Total power production was calculated using a 65 percent capacity factor.

2000

Year 2000 estimates of nuclear power production were calculated for 3 possible annual growth rates (1%, 3%, 5%) in total electric energy consumption in the market areas. The calculation assumes that 50 percent of all new electric generating capacity within the All FGD market area between 1985 and 2000 will be nuclear fueled. Similarly, 40 percent of the post 1985 generating capacity of the All SCS market area will be nuclear fueled. The year 2000 annual power production is calculated by adding either one-half (All FGD market) or two-fifths (All SCS market) of the 1985-2000 increase in electric power consumption at the 3 different growth rates to the 1985 annual nuclear power production.

Table E: Subtotal: Hydroelectric, Nuclear, and Gas Fueled Generation

The projections in Table E are the total of Tables C and D with the appropriate gas fueled electric generation total added (236.5 billion KWH/Yr for the All FGD market and 177.3 billion KWH/Yr for the All SCS market). Gas fired generation was held constant at 1973 levels for all our projections to the year 2000.

Table F: Coal Generation as a Residual Given Hydroelectric, Nuclear, and Gas Fueled Generation

Table F, residual coal-fired electric generation is calculated by subtracting the data in Table E, the hydroelectric, nuclear, and gas fueled subtotal from Table A, the total electric generation. This calculation assumes that oil fired electric generation in the Northern Great Plains coal

market areas is zero. In 1973, oil-fired generation actually made up 3.8% of the total generation in the All FGD market area and 1.8% in the All SCS market area.

Table G: Coal Source Projection: Assume that the NGP Supplies All Coal for Electric Generation in Its Market Area. Coal Production Assumption: Coal-Fired Generation Maintains its Current Share of Electric Energy Production Within Its Market Area.

Table G is calculated by converting Table B from electric generation to tons of coal required to produce that generation. The All FGD market area generation was converted to coal production using a conversion factor of 1.9698×10^3 KWH/ton, the market area average based on the FPC News, May 24, 1974, p. 237. Similarly, the All SCS market area conversion factor was 1.5533×10^3 KWH/ton. The Partial FGD market was then calculated in the normal manner. (The All FGD change was added to the All SCS base.)

Table H: Coal Source Projection: Assume that the NGP Supplies All Coal for Electric Generation in Its Market Area. Coal Production Assumption: The Residual Share of the Fuel Mix Within the NGP Market Area will be Filled by Coal-Fired Generation.

The 1973 base coal production was obtained by converting the base generation in Table B to coal production. The base coal production in this table is identical to that of Table G. Oil-fired generation was assumed to go to zero between 1973 and 1980, being replaced by coal generation. The projections for 1980, 1985, and 2000 were made by converting the generation data in Table F to coal production using the appropriate conversion factors. The Partial FGD market was calculated in the normal manner except that oil-fired generation was considered to go to zero before 1980.

Table I: Coal Source Projection: Assume That the NGP Continues to Supply its 1980 Contract-Based Share of Electric Utility Coal Consumption. Coal Production Assumption: Coal-Fired Generation Maintains its Current Share of Electric Energy Production.

The NGP coal market share shown in Table I is the actual 1980 NGP coal contract estimate for each market (Table I, 1980) divided by the coal production estimate for each market area, assuming that coal-fired generation maintains its current share of electric energy production, and that the NGP supplies all coal for electric generation in its market area (Table G, 1980). The 1980 contract estimate for the Partial FGD market area was defined to be identical to the estimate for the All FGD market area since no empirical basis for identifying a 1980 contract estimate for the Partial FGD market area exists (i.e., we do not know whether coal contracts in the "swing" states are going to new or existing plants). The 1985 and 2000 estimates for the All FGD and All SCS market areas in Table I were calculated by multiplying the 1985 and 2000 coal production estimates in Table G by their respective market share at 5% annual constant growth in electric energy consumption. The 5% growth share was used because at least that growth rate is implicit in utilities expectations and it is unlikely, if growth rates are lower than 5%, that the NGP coal source share will increase at the expense of other coal producing regions.

The 1985 and 2000 Partial FGD market estimates were calculated using the All FGD market share. The resulting Partial FGD estimate is probably low since the NGP coal producing region is likely to have a larger relative share in the smaller market area.

Table J: Coal Source Projection: Assume that the NGP Continues to Supply its 1980 Contract-Based Share of Electric Utility Coal Consumption. Coal Production Assumption: The Residual Share of the Fuel Mix Within the NGP Market Area Will be Filled by Coal-Fired Generation.

The procedure used to calculate Table J was identical to that used in the calculation of Table I. The market share was determined from Table H while actual 1980 contract data and the 5% growth market share were used to calculate 1985 and 2000 estimates.

Table K: Coal Source Projection: Assume that the NGP Supplies All Coal for New Electric Generation in its Market Area. Coal Production Assumption: Coal-Fired Generation Maintains its Current Share of Electric Energy Production.

The 1973 base NGP coal production data come from the Northern Great Plains Resources Program Draft Summary Report, September, 1974. Projections for 1980, 1985, and 2000 were made by simply adding the change in coal production from Table G to the 1973 base. The All FGD and Partial FGD estimates are identical to this configuration since our coal source projection states that the NGP supplies all coal for new generation within its market area and the Partial FGD estimate requires FGD for all new coal-fired generating plants as does the All FGD estimate. In both cases, it is assumed that existing coal-fired electric generating plants are fueled with coal from other sources.

Table L: Coal Source Projection: Assume that the NGP Supplies All Coal for New Electric Generation in Its Market Area. Coal Production Assumption: The Residual Share of the Fuel Mix Within the NGP Market Area will be Filled by Coal-Fired Generation.

The procedure used to calculate Table L was identical to that used in the calculation of Table K. The projections for 1980, 1985, and 2000 were made by adding the change in coal production from Table H to the 1973 base. Again, the All FGD and Partial FGD estimates are identical.

Table M: Consumption of NGP Coal for Gasification.

The number of coal gasification plants projected for the Northern Great Plains was determined by Richard Stroup and Walter Thurman in the Montana University Coal Demand Study Working Paper #2. Coal consumption was calculated by multiplying the projected number of plants by the annual coal consumption per plant.

Table N: Coal Replacement Projection (Coal Production from the NGP to Replace Natural Gas Shortfalls).

Table N was calculated by Walter Thurman and Richard Stroup in the Montana University Coal Demand Study Working Paper #14. The methodology is as follows:

1. A base projection for industrial gas demand in the 21-state All FGD market area for NGP coal is determined. Dupree and West's national projection for industrial gas demand in the year 2000 is broken up into state shares according to current consumption percentages. That is, increases in gas demand are assigned to states in the same proportions in which current gas supply is consumed. The 21 states now make up 65.01% of national industrial gas consumption.

2. Coal costs are calculated for the 21-state area, as divided into 10 regions. Coal costs include: \$5, \$6, and \$7.50 per ton production prices (three different projections), \$.007/mile/ton transportation costs, and a pollution control premium of \$1.12/ton. In the analysis, it is assumed that NGP coal is a least-cost alternative to gas in the market area and competes on the basis of the calculated costs.

3. For each of the 10 regions within the market area, current industrial gas consumption is hypothetically reduced by assuming current users are faced with the direct combustion of coal as their least cost choice. This gives a demand response to an increase in energy prices from those which they now pay for gas to those which they would pay for NGP coal. An economy-wide energy demand elasticity of -0.15 is used in the equation:

$$\frac{\Delta Q}{Q} = -0.15 \times \frac{\Delta P}{P}, \text{ percentage change in quantity} = \text{elasticity} \times \text{percentage change in price.}$$

The elasticity equation is used to deflate Dupree and West's base projection. They use an average 3.3% annual growth figure for industrial energy use and do not consider a price-induced demand reduction, though they do consider price sensitive inter-fuel substitution.

4. The percentage demand response for the 21 states is projected onto Dupree and West's industrial gas demand forecast. It is assumed here that coal will be substituted for increases in gas demand only. Current gas users are assumed to have the same quantities of gas available to them as are available now.

5. If natural gas supply is short, the development of coal gasification to augment gas supply becomes more likely. We then turn to the high forecast of gasification activity and subtract from the gas demand that which would be supplied by the three projected plants.

The resultant increase in industrial gas demand forecasted is then converted into equivalent tons of coal.

6. Finally a share of this demand is allocated to Northern Great Plains coal. We arbitrarily assumed that the NGP coal market share at 5% annual growth in electricity consumption for the All FGD market (0.67) would hold for the direct substitution of coal as a boiler fuel. Thus the NGP coal demand for natural gas substitution was determined by multiplying that projected total coal substitution demand by the NGP coal market share.

7. The coal substitution demand calculated was for the year 2000. We arbitrarily assumed that one half of this increased coal production would be required by 1985.

2. Methodological Appendix--Price Sensitive Projection

• Table A: Price Sensitive Total Electric Generation for the NGP Coal Market Area.

. The 1973 base generation is identical to Table A of Appendix I. The projections of 1980, 1985 and 2000 price sensitive electric generation were calculated through the use of a computer program fully described in the Montana University Coal Demand Study Working Paper #12, by John Duffield and Terry Wheeling.

Table B: Price Sensitive Fuel Mix Projection: Coal-Fired Generation Maintains its Current Share of Electric Energy Production.

. The calculation procedure for Table B in Appendix II is identical to that used for Table B in Appendix I.

• Table C: Hydroelectric Generation.

Table C is identical to Table C, Appendix I.

Table D: Price Sensitive Nuclear Fueled Generation.

. The 1973 base nuclear fueled generation and the 1980 and 1985 projections are identical to Table D, Appendix I. The year 2000 projections were calculated by assuming that 50% of the new projected price sensitive electric generation (Table A, Appendix II) growth between 1985 and 2000 would be nuclear fueled for the All FGD market area. Similarly it was assumed that 40% of the 1985-2000 price sensitive generation growth would be nuclear fueled in the All SCS market area. The year 2000 Partial FGD market estimate was calculated by the normal procedure.

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Table E: Price Sensitive Subtotal: Hydroelectric, Nuclear, and Gas Fueled Generation.

The calculation procedure for Table E in Appendix II is identical to that used for Table E in Appendix I.

Table F: Price Sensitive Coal Generation as a Residual Given Hydroelectric, Nuclear and Gas Fueled Generation.

The calculation procedure for Table F in Appendix II is identical to that used for Table F in Appendix I.

Table G: Coal Source Projection: Assume that the NGP Supplies All Coal for Electric Generation in Its Market Area. Price Sensitive Coal Production Assumption: Coal-Fired Generation Maintains its Current Share of Electric Energy Production Within its Market Area.

The calculation procedure for Table G in Appendix II is identical to that used for Table G in Appendix I.

Table H: Coal Source Production: Assume that the NGP Supplies All Coal for Electric Generation in its Market Area. Price Sensitive Coal Production Assumption: The Residual Share of the Fuel Mix Within the NGP Market Area Will be Filled by Coal-Fired Generation.

The calculation procedure for Table H in Appendix II is identical to that used for Table H in Appendix I.

Table I: Coal Source Projection: Assume that the NGP Continues to Supply its 1980 Contract-Based Share of Electric Utility Coal Consumption. Price Sensitive Coal Production Assumption: Coal-Fired Generation Maintains its Current Share of Electric Energy Production.

The calculation procedure for Table H in Appendix II is identical to that used for Table H in Appendix I, except that the 1985 and 2000 estimates for the All FGD and All SCS market areas in Table I, Appendix II were calculated by multiplying the 1985 and 2000 coal production estimates in Table G, Appendix II, by the respective market shares for the (FPC, 3%) Electric-Gas Annual Price Growth Assumption.

Table J: Coal Source Projection: Assume that the NGP Continues to Supply its 1980 Contract-Based Share of Electric Utility Coal Consumption. Coal Production Assumption: The Residual Share of the Fuel Mix Within the NGP Market Area Will be Filled by Coal-Fired Generation.

The calculation procedure for Table J in Appendix II is identical to that used for Table I in Appendix II. The market share was determined from Table H, Appendix II, and actual 1980 contract data and the (FPC, 3%) Electric Gas Annual Price Growth Assumption were used to calculate 1985 and 2000 estimates.

PART III

WORKING PAPERS

- #1 - "Electric Energy Demand and the Demand for Northern Great Plains' Coal," by Thomas M. Power.
- #2 - "Forecasting Coal Gasification Activity," by Richard Stroup and Walter Thurman.
- #3 - "The Geographic Market for NGP Coal," by Terry Wheeling.
- #4 - "NGP Coal Contract Data," by William Tomlinson.
- #5 - "Nuclear Energy Raw Material Supply," by Arnold Silverman.
- #6 - "Projections of Hydroelectric Generation in the Northern Great Plains Coal Market Area," by John McBride.
- #7 - "Projections of Nuclear Fueled Electric Generation in the Northern Great Plains Coal Market Area," by John McBride.
- #8 - "Costs of Flue Gas Desulfurization for Electric Generating Plants," by John McBride.
- #9 - "Advanced Coal Cleaning and Energy Conversion," by John McBride.
- #10 - "Potential for Conversion of Oil to Coal-Fired Steam Electric Generators," by John McBride.
- #11 - "The Status of Supplementary Control Systems," by John McBride.
- #12 - "Econometric Projection of Electric Energy Demand in the Northern Great Plains Coal Market Area," by John Duffield and Terry Wheeling.
- #13 - "Environmental Laws and Regulations of Northern Great Plains Coal Market Area Swing States," by William Tomlinson.
- #14 - "Northern Great Plains Coal Use in Response to Natural Gas Shortfalls," by Walter Thurman and Richard Stroup.

PART IV

COMPUTER PRINTOUT AND PROGRAMS

- A. Montana University Coal Demand Study Electric
Energy Demand Projections, Volumes I and II.
- B. Montana University Coal Demand Study Programs.

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